Attachment 3.1-4

Notice of Preliminary Determination of Compliance (PDOC)

Project Number: N1011254–Tracy Peaker Project (01-AFC-16)

San Joaquin Valley
Air Pollution Control District

September 5, 2001

Mr. Doug Wheeler
GWF Energy, LLC
4300 Railroad Avenue
Pittsburg, CA 94565

Re: Notice of Preliminary Determination of Compliance (PDOC)
Project Number: N1011254 – Tracy Peaker Project (01-AFC-16)

Dear Mr. Wheeler:

Enclosed for your review and comments is the District's preliminary determination of compliance (PDOC) of GWF Energy's proposal for the installation of a nominal 169 MW simple cycle power plant to be located at SW ¼ Section 36, Township 2 South, Range 4 East – MDB&M, southwest of the city of Tracy, in western San Joaquin County.

The notice of preliminary decision for this project will be published approximately three days from the date of this letter. Please submit your written comments to SJVAPCD, 4230 Kiernan Avenue #130, Modesto, CA 95356 within the 30-day public comment period which begins on the date of publication of the public notice.

Thank you for your cooperation in this matter. If you have any questions regarding this matter, please contact Mr. Jim Swaney or Mr. Nick Peirce of Permit Services at (209) 557-6400.

Sincerely,

Seyed Sadredin
Director of Permit Services

SS:NP/mma
Enclosures
c: Jim Swaney, Permit Services Manager

Stockton Record
Project #N-1011254

NOTICE OF PRELIMINARY DETERMINATION OF COMPLIANCE FOR A SIMPLE CYCLE POWER PLANT

NOTICE IS HEREBY GIVEN that the San Joaquin Valley Unified Air Pollution Control District solicits public comment on the Preliminary Determination of Compliance for GWF Energy, LLC for the installation of a nominal 169 MW simple cycle power plant, to be located at the SW ¼ Section 36, Township 2 South, Range 4 East MDB&M, southwest of the city of Tracy, in western San Joaquin County.

The analysis of the regulatory basis for these proposed actions, Project #N-1011254, is available for public inspection at the District office at the address below. Written comments on this project must be submitted within 30 days of the publication date of this notice to **SEYED SADREDIN, DIRECTOR OF PERMIT SERVICES, SAN JOAQUIN VALLEY UNIFIED AIR POLLUTION CONTROL DISTRICT, 4230 KIERNAN AVENUE #130, MODESTO, CA 95356.**

DETERMINATION OF COMPLIANCE EVALUATION

Tracy Peaker Project
California Energy Commission
Application for Certification Docket #: 01-AFC-16

Facility Name:	GWF Energy, LLC – Tracy Peaker Power Plant
Mailing Address:	4300 Railroad Avenue Pittsburg, CA 94565
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Engineer:	Nick Peirce, Senior Air Quality Engineer
Lead Engineer:	Jim Swaney, Permit Services Manager
Date:	September 2, 2001
Project #:	N1011254
Application #'s:	N-4597-1-0, N4597-2-0, and N-4597-3-0
Submitted:	August 16, 2001

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ATTACHMENT A - Proposed Conditions

ATTACHMENT B - CTG Emissions Data

ATTACHMENT C - Referenced BACT Guidance Documents

ATTACHMENT D - Top Down BACT Analysis

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ATTACHMENT F - Ambient Air Quality Modeling Summary

I. PROPOSAL:

GWF Energy, LLC – Tracy Peaker Power Plant hereinafter referred to as "Tracy Peaker Project" is seeking approval from the San Joaquin Valley Air Pollution Control District (the "District") for the installation of a "peaking" electrical power generation facility. The Tracy Peaker Project will be a simple cycle power generation facility consisting of two natural gas fired combustion turbine generators (CTG's), with a nominal output of 169 megawatts (MW) electrical power, and associated facilities. The project will interconnect to the PG&E Tesla Substation through a 5 mile, 230 kV transmission line.

The Tracy Peaker Project is subject to approval by the California Energy Commission (CEC). Pursuant to SJVAPCD Rule 2201, Section 5.8, the Determination of Compliance (DOC) review is functionally equivalent to an Authority to Construct (ATC) review. The Determination of Compliance (DOC) will be issued and submitted to the CEC contingent upon SJVAPCD approval of the project.

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

II. APPLICABLE RULES:

Rule 1080 Stack Monitoring (12/17/92)
Rule 1081 Source Sampling (12/16/93)
Rule 2201 New and Modified Stationary Source Review (8/20/98)
Rule 2520 Federally Mandated Operating Permits (6/15/95)
Rule 2540 Acid Rain Program (11/13/97)
Rule 4001 NSPS Subpart GG - Standards of Performance for Stationary Gas Turbines
Rule 4101 Visible Emissions (12/17/92)
Rule 4102 Nuisance (12/17/92)
Rule 4201 Particulate Matter Concentration (12/17/92)
Rule 4202 Particulate Matter Emission Rate (12/17/92)
Rule 4701 Internal Combustion Engines (11/12/98)
Rule 4703 Stationary Gas Turbines (10/16/97)
Rule 4801 Sulfur Compounds (12/17/92)
Rule 8010 Fugitive Dust Administrative Requirements for Control of Fine Particulate Matter (4/25/96)
Rule 8020 Fugitive Dust Requirements for Control of Fine Particulate Matter (PM-10) From Construction, Demolition, Excavation, and Extraction Activities (4/25/96)
CH&S Code, Sections 41700, 42301.6 (School Notice), and 44300 (Air Toxic "Hot Spots")

III. PROJECT LOCATION:

SW ¼ Section 36, Township 2 South, Range 4 East – MDB&M, APN 209-240-11

The site is located in southwest of the city of Tracy, in western San Joaquin County. The proposed location is not within 1000' of a K-12 school.

IV. PROCESS DESCRIPTION:

The proposed facility will consist of two natural gas-fired General Electric (GE) model PG7121 EA combustion turbine generators (CTG's), each equipped with dry-low NO_x combustors, a selective catalytic reduction (SCR) system with ammonia injection, an oxidation catalyst, and associated support equipment. Each CTG system will consist of a stationary, heavy duty, industrial CTG, designed to use natural gas to produce electricity at a nominal output of 84.4 MW for each CTG. The total facility nominal output will be 169 MW. No cooling towers or heat recovery steam generators (HRSG's) will be installed. The applicant has not proposed any black start equipment, but has proposed to install a 250 kW diesel-fired emergency generator to provide auxiliary electrical power in the event of a total loss of electrical power.

The CTG's will operate during periods of peak electricity demand. Peak electricity demand periods typically occur during daylight hours in the second and third quarters of the calendar year, but can also occur during other periods when unusual temperature extremes cause unseasonably high electricity demand or when other electricity resource constraints reduce the amount of power otherwise available to the grid. This facility could operate during any of these periods.

The facility has proposed an operating scenario of 8,000 hours of full load operation per year with 250 total startups and shutdown equally divided among the calendar year as shown in the table below:

N-4597-1-0 and N-4597-2-0: Tracy Peaker Project - Operating Scenario					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startups	62	62	63	63	250
Number of Shutdowns	62	62	63	63	250
Number of Full Load Hours	2000	2000	2000	2000	8,000

The CTG's will utilize dry low NO_x (DLN) combustors, SCR with ammonia injection, and an oxidation catalyst to achieve the following emission rates:
NO_X: 5.0 ppmvd @ 15% O_2
VOC: 2.0 ppmvd @ 15% O_2
CO: 6.0 ppmvd @ 15% O_2
SO_X: 0.00071 lb/MMBtu
PM_{10}: 0.0112 lb/MMBtu

IV. PROCESS DESCRIPTION (Continued):

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

V. EQUIPMENT LISTING:

N-4597-1-0: 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

N-4597-2-0: 84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

N-4597-3-0: 382 HP CATERPILLAR MODEL ATAAC DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 250 KW ELECTRICAL GENERATOR

The diesel-fired IC engine is equipped with:

✓ Turbocharger
✓ Aftercooler
✓ Positive crankcase ventilation (PCV)

VI. EMISSION CONTROL TECHNOLOGY EVALUATION:

N-4597-1-0 and N-4597-2-0 (Turbines)

Each CTG will be equipped with an inlet air filtration and cooling system, dry low NOx (DLN) combustors, a selective catalytic reduction system with ammonia injection, and an oxidation catalyst. DLN combustors can achieve a NO_X emission rate of 9 ppmvd @ 15% O_2 without the use of water or steam injection. The use of DLN combustors and a SCR system with ammonia injection can achieve a NO_X emission rate of 5 ppmvd @ 15% O_2 from a simple cycle, industrial frame CTG [(1)]. CO emissions of 6 ppmvd @ 15% O_2 and VOC emissions of 2 ppmvd @ 15% O_2 have been demonstrated with the use of an oxidation catalyst [(1)].

DLN burner technology uses a two-stage combustor that premixes a portion of the air and fuel in the first stage and the remaining air and fuel are injected into the second stage. This two-stage process optimizes the mixing of combustion air and fuel, thereby minimizes the amount of air required and controlling peak flame temperatures, which results in low NO_x emissions.

The SCR system consists of ammonia injection in the GTG exhaust upstream of the catalyst and a catalyst bed. The ammonia reduces NO_x to N_2 and O_2 in the presence if the catalyst. Unreacted ammonia (ammonia slip) is present in the GTG exhaust. Ammonia slip will be limited to 10 ppmvd @ 15% O_2.

An oxidation catalyst utilizes a precious metal catalyst bed to convert carbon monoxide (CO) to carbon dioxide (CO_2). This type of control device is also somewhat effective for controlling VOC emissions by a similar chemical reaction to that of carbon monoxide.

N-4597-3-0 (Emergency IC engine)

The emission control devices/technologies and their effect on diesel engine emissions are detailed below.[(2)]

The turbocharger reduces the NO_X emission rate from the engine by approximately 10% by increasing the efficiency and promoting more complete burning of the fuel. The aftercooler functions in conjunction with the turbocharger 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 by approximately 15%. The use of low sulfur (0.05% by weight sulfur maximum) diesel fuel reduces SO_X emissions by approximately 90% from standard diesel fuel. The PCV system reduces crankcase VOC and PM_{10} emissions by at least 90% over an uncontrolled crankcase vent.

[1] Based on information supplied by the CTG manufacturer and information contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document.
[2] From "Non-catalytic NO_x Control of Stationary Diesel Engines", by Don Koeberlein, CARB.

VII. CALCULATIONS:

A. Assumptions

N-4597-1-0 and N-4597-2-0 (Turbines)

- BACT emission concentration limits of 5.0 ppmvd @ 15% O_2, 6.0 ppmvd @ 15% O_2, and 2.0 ppmvd @ 15% O_2 are proposed for NO_x, CO, and VOC, respectively, at all operating loads (except during start-ups and shutdowns).

- The applicant proposes NO_X, CO and VOC mass emission rates of 18.37 lb/hr, 7.64 lb/hr and 1.59 lb/hr, respectively, at 100% load and 59 °F (average ambient temperature).

- The applicant proposes a PM_{10} mass emission rate of 10.3 lb/hr for each CTG based on the vendor's guarantee for both the filterable and condensable portions of PM_{10}.

- A SO_X emissions rate of 0.70 lb/hr was calculated using the CTG's maximum heat input of 990.6 MMBtu/hr (@ 100% load and 59 °F) by performing a mass balance assuming 1000 Btu/scf (hhv) for natural gas, and a natural gas sulfur content of 0.25 gr S/100 scf.

- The maximum total hourly NO_X and CO emissions used in the dispersion modeling are based on each CTG experiencing one 20 minute startup and operating the remaining 40 minutes @ 100% load and 15 degrees F. This is equivalent to one turbine having two consecutive 20 minute startups and operating the remaining 20 minutes at full capacity while the other turbine operates the entire 60 minutes at full capacity. Therefore, the maximum duration of a startup/shutdown event will be limited to 40 minutes, based on two consecutive 20 minute startups. Maximum hourly limits for the facility are not necessary for the other pollutants (SO_X , PM10, VOC) which are either dependent on fuel usage or for which there is no one hour ambient air quality standard.

- Maximum daily emissions for each CTG were estimated assuming 100% capacity, an ambient temperature of 59 °F, one 20 minute startup, followed by 23 1/6 hours of full load operation, and one 30 minute shutdown.

- SO_X emissions are proportional to fuel use, so the maximum daily emission rate is based on 24 hours of operation, @ 100% capacity and 59 °F.

- Quarterly emissions are based on the following hypothetical operating schedule:

VII. CALCULATIONS (Continued):

N-4597-1-0 and N-4597-2-0: Tracy Peaker Project - Hypothetical Operating Scenario (Repeated from P. 2)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Number of Startups	62	62	63	63	250
Number of Shutdowns	62	62	63	63	250
Full Load Hours	2000	2000	2000	2000	8,000

N-4597-3-0 (Emergency IC engine)

operating schedule:	24 hours/day maximum emergency use 200 hours/year maximum non-emergency use
density of diesel fuel:	7.1 lb/gal (AP-42, Appendix A)
EPA F-factor (60 °F):	9,051 dscf/MMBtu
fuel heating value:	140,000 Btu/gal (AP-42, Table 3.3-1)
BSFC:	7,000 Btu/hp-hr (AP-42, Table 3.3-1)
fuel rate:	19 gal/hr @ 100% load

B. Emission Factors

N-4597-1-0 and N-4597-2-0 (Turbines)

The maximum air contaminant mass emission rates (lb/hr), concentrations (ppmvd @ 15% O_2), and startup and shutdown emissions rates estimated by the manufacturer (see Appendix ?? for manufacturer's emissions data) for the proposed CTG's are summarized below:

Maximum Emission Rates and Concentrations (@ 100% Load & 59 °F)						
	NO_X	VOC	CO	PM_{10}	SO_X	NH_3
Mass Emission Rates (per turbine, lb/hr)	18.37	1.59	7.64	10.3	0.70	13.19
ppmvd @ 15% O_2 limits	5.0	2.0	6.0	--	--	10.0

Startup and Shutdown Emissions (20 min. startup, 30 min. shutdown)					
	PM_{10} (lb/event)	SO_x (lb/event)	NO_x (lb/event)	VOC (lb/event)	CO (lb/event)
Mass Emission Rate (per turbine)	2.6	N/A[3]	13.0	1.27[4]	21.0

[3] SO_X emissions during startups and shutdowns are always lower than maximum hourly emissions as SO_X emissions are proportional to fuel flow.
[4] No manufacturer startup or shutdown VOC emissions data are available. Therefore, the startup and shutdown emission rate is estimated based on the worst case scenario of a 30 minute portion of the maximum hourly emission rate at 2.0 ppmvd @ 15% O_2 as follows: 2.54 lb/hr × 30/60 hr = 1.27 lb/event.

VII. CALCULATIONS (Continued):

N-4597-3-0 (Emergency IC engine)

The emission factors (EF) for NO_x, CO, VOC, and PM_{10} emissions for this unit are as identified by the manufacturer. The EF for SO_x for this engine when burning diesel fuel is based on mass balance with 0.05% sulfur as proposed by the applicant.

EF_{NOx} = 5.09 g/bhp-hr
EF_{VOC} = 0.14 g/bhp-hr
EF_{CO} = 1.13 g/bhp/hr
EF_{PM10} = 0.13 g/bhp/hr

EF_{SOx} = 0.05% sulfur in fuel × 1/100 × 7.1 lb fuel/gal fuel × (2 lb SO_2 in exhaust/1 lb S in fuel) × 19 gal/hr
= 0.135 lb/hr

C. <u>Potential to Emit (PE):</u>

Section 3.26 of Rule 2201 defines the potential to emit (PE) as the maximum capacity of an emissions unit to emit a pollutant under its physical and operational design. The criteria pollutant potentials to emit for each emission unit is presented below:

1. Maximum Hourly Emissions

N-4597-1-0 and N-4597-2-0 (Turbines)

The maximum hourly emissions from each CTG will occur when the unit undergoes one 20 minute startup event followed by 40 minutes of operation at 100% load. The maximum hourly emissions are calculated as follows, and summarized in the table below:

VII. CALCULATIONS (Continued):

$$PE\left(\frac{lb}{hr}\right) = \left(\frac{1\text{ startup event}}{hr} \times \text{startup emissions}\left(\frac{lb}{event}\right)\right) + \left(\frac{40}{60} \times \text{mass emission rate}\left(\frac{lb}{hr}\right)\right)$$

Maximum Hourly Emissions				
	Startup Emissions (lb/event)	Turbine #1 Emissions (1 startup and 40 min @ 100% load)	Turbine #2 Emissions (1 startup and 40 min @ 100% load)	Maximum Hourly Emissions for Both Turbines
NO_X	13 lb	25.25 lb	25.25 lb	50.50 lb/hr
VOC	1.27 lb	2.33 lb	2.33 lb	4.66 lb/hr
CO	21 lb	20.09 lb	20.09 lb	40.18 lb/hr
PM_{10}	N/A[5]	10.30 lb	10.30 lb	20.60 lb/hr
SO_X	N/A[5]	0.70 lb	0.70 lb	1.40 lb/hr
NH_3	N/A[5]	13.19 lb	13.19 lb	26.38 lb/hr

N-4597-3-0 (Emergency IC engine)

The PE for this unit is based on the maximum operating capacity of the engine. The following calculation is representative of emission calculations for all pollutants except SO_x. Emission calculations for SO_x are detailed in Section VII.B of this document.

$$PE\left(\frac{lb}{hr}\right) = bhp \times EF\left(\frac{g}{hp\text{-}hr}\right) \times \left(\frac{lb}{453.6\text{ g}}\right)$$

Maximum Hourly Emissions	
Pollutant	Maximum Hourly Emissions
NO_X	4.29 lb/hr
VOC	0.12 lb/hr
CO	0.95 lb/hr
PM_{10}	0.11 lb/hr
SO_X	0.14 lb/hr

[5] The maximum hourly emissions for this pollutant occur when each CTG operates at 100% load for 1 hour.

VII. CALCULATIONS (Continued):

2. *Maximum Daily PE*

N-4597-1-0 and N-4597-2-0 (Turbines)

The maximum daily emissions occur when each CTG undergoes one 20 minute startup period, followed by 23 hours and 10 minutes operation at 100% load, then one 30 minute shutdown period. The calculations are similar to that for the maximum hourly emissions. The results are summarized in the table below:

Maximum Daily Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	DEL (per CTG)	Combined DEL for 2 CTG's
NO_X	13 lb	18.37 lb/hr	425.6 lb/day	451.6 lb/day	903.2 lb/day
VOC	1.27 lb	1.59 lb/hr	36.8 lb/day	39.4 lb/day	78.8 lb/day
CO	21 lb	7.64 lb/hr	177.0 lb/day	219.0 lb/day	438.0 lb/day
PM_{10}	N/A[6]	10.3 lb/hr	247.2 lb/day	247.2 lb/day	494.4 lb/day
SO_X	N/A[6]	0.70 lb/hr	16.8 lb/day	16.8 lb/day	33.6 lb/day
NH_3	N/A[6]	13.19 lb/hr	316.6 lb/day	316.6 lb/day	633.2 lb/day

N-4597-3-0 (Emergency IC engine)

The maximum daily emissions occur when this unit is operated 24 hours per day. The calculations are similar to those performed for the maximum hourly emissions. The results are summarized in the table below:

Maximum Daily Emissions	
Pollutant	Maximum Daily Emissions
NO_X	103.0 lb/day
VOC	2.9 lb/day
CO	22.8 lb/day
PM_{10}	2.6 lb/day
SO_X	3.4 lb/day

[6] Maximum daily emissions for this pollutant occur when each CTG is operated at 100% load for 24 hr/day.

VII. CALCULATIONS (Continued):

3. Maximum Quarterly PE

N-4597-1-0 and N-4597-2-0 (Turbines)

Maximum quarterly emissions for each unit will be determined by the following equation:

$$PE\left(\frac{lb}{qtr}\right) = \left(\frac{startups}{qtr} \times startup\ emissions\left(\frac{lb}{event}\right)\right) + \left(2{,}000\frac{hr}{qtr} \times mass\ emission\ rate\left(\frac{lb}{hr}\right)\right) + \left(\frac{shutdowns}{qtr} \times shutdown\ emissions\left(\frac{lb}{event}\right)\right)$$

Quarters 1 and 2

The maximum emissions from each CTG during the first and second quarters will occur when each unit undergoes sixty-two (62) startup events, 2,000 hours of operation at 100% load, followed by sixty-two (62) shutdown events. The maximum hourly emissions are calculated as follows, and summarized in the tables below:

First Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTG's
NO_X	13 lb	18.37 lb/hr	36,740 lb/qtr	38,352 lb/qtr	76,704 lb/qtr
VOC	1.27 lb	1.59 lb/hr	3,180 lb/qtr	3,338 lb/qtr	6,676 lb/qtr
CO	21 lb	7.64 lb/hr	15,280 lb/qtr	17,884 lb/qtr	35,768 lb/qtr
PM_{10}	N/A(7)	10.3 lb/hr	20,600 lb/qtr	20,600 lb/qtr	41,200 lb/qtr
SO_X	N/A(7)	0.70 lb/hr	1,400 lb/qtr	1,400 lb/qtr	2,800 lb/qtr
NH_3	N/A(7)	13.19 lb/hr	26,380 lb/qtr	26,380 lb/qtr	52,760 lb/qtr
Second Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTG's
NO_X	13 lb	18.37 lb/hr	36,740 lb/qtr	38,352 lb/qtr	76,704 lb/qtr
VOC	1.27 lb	1.59 lb/hr	3,180 lb/qtr	3,338 lb/qtr	6,676 lb/qtr
CO	21 lb	7.64 lb/hr	15,280 lb/qtr	17,884 lb/qtr	35,768 lb/qtr
PM_{10}	N/A(7)	10.3 lb/hr	20,600 lb/qtr	20,600 lb/qtr	41,200 lb/qtr
SO_X	N/A(7)	0.70 lb/hr	1,400 lb/qtr	1,400 lb/qtr	2,800 lb/qtr
NH_3	N/A(7)	13.19 lb/hr	26,380 lb/qtr	26,380 lb/qtr	52,760 lb/qtr

7 Maximum quarterly emissions for this pollutant occur when each CTG is operated at 100% load for 2,000 hr/qtr.

VII. CALCULATIONS (Continued):

Quarters 3 and 4
The maximum emissions from each CTG during the first and second quarters will occur when each unit undergoes sixty-two (63) startup events, 2,000 hours of operation at 100% load, followed by sixty-two (63) shutdown events. The maximum hourly emissions are calculated as follows, and summarized in the tables below:

Third Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTG's
NO_X	13 lb	18.37 lb/hr	36,740 lb/qtr	38,378 lb/qtr	76,756 lb/qtr
VOC	1.27 lb	1.59 lb/hr	3,180 lb/qtr	3,340 lb/qtr	6,680 lb/qtr
CO	21 lb	7.64 lb/hr	15,280 lb/qtr	17,926 lb/qtr	35,852 lb/qtr
PM_{10}	N/A[(8)]	10.3 lb/hr	20,600 lb/qtr	20,600 lb/qtr	41,200 lb/qtr
SO_X	N/A[(8)]	0.70 lb/hr	1,400 lb/qtr	1,400 lb/qtr	2,800 lb/qtr
NH_3	N/A[(8)]	13.19 lb/hr	26,380 lb/qtr	26,380 lb/qtr	52,760 lb/qtr
Fourth Quarter Emissions					
	Startup/ Shutdown Emissions (lb/event)	Emissions Rate @ 100% Load	Emissions @ Normal Operation	Quarterly PE (per CTG)	Combined PE for 2 CTG's
NO_X	13 lb	18.37 lb/hr	36,740 lb/qtr	38,378 lb/qtr	76,756 lb/qtr
VOC	1.27 lb	1.59 lb/hr	3,180 lb/qtr	3,340 lb/qtr	6,680 lb/qtr
CO	21 lb	7.64 lb/hr	15,280 lb/qtr	17,926 lb/qtr	35,852 lb/qtr
PM_{10}	N/A[(8)]	10.3 lb/hr	20,600 lb/qtr	20,600 lb/qtr	41,200 lb/qtr
SO_X	N/A[(8)]	0.70 lb/hr	1,400 lb/qtr	1,400 lb/qtr	2,800 lb/qtr
NH_3	N/A[(8)]	13.19 lb/hr	26,380 lb/qtr	26,380 lb/qtr	52,760 lb/qtr

[8] Maximum quarterly emissions for this pollutant occur when each CTG is operated at 100% load for 2,000 hr/qtr.

VII. CALCULATIONS (Continued):

N-4597-3-0 (Emergency IC engine)

The non-emergency operation is equally divided among the calendar year at 50 hours per quarter. The calculations are similar to those performed for the maximum daily emissions. The results are summarized in the table below:

Quarterly Emissions				
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
NO_X	215 lb	215 lb	215 lb	215 lb
VOC	6 lb	6 lb	6 lb	6 lb
CO	48 lb	48 lb	48 lb	48 lb
PM_{10}	6 lb	6 lb	6 lb	6 lb
SO_X	7 lb	7 lb	7 lb	7 lb

4. Maximum Annual PE

N-4597-1-0 and N-4597-2-0 (Turbines)

The maximum annual PE is merely the sum of the maximum quarterly PE calculated in section VII.C.3 of this document. The results are summarized in the table below:

Maximum Annual Emissions (both CTG's)						
Quarter	NO_X	VOC	CO	PM_{10}	SO_X	NH_3
1st (lb)	76,704	6,676	35,768	41,200	2,800	52,760
2nd (lb)	76,704	6,676	35,768	41,200	2,800	52,760
3rd (lb)	76,756	6,680	35,852	41,200	2,800	52,760
4th (lb)	76,756	6,680	35,852	41,200	2,800	52,760
Annual PE (lb/yr)	306,920	26,712	143,240	164,800	11,200	211,040

N-4597-3-0 (Emergency IC engine)

The maximum non-emergency operation will not exceed 200 hours per year. The calculations are similar to those performed for the maximum daily emissions. The results are summarized in the table below:

Maximum Annual Emissions	
Pollutant	Maximum Annual Emissions
NO_X	858 lb/yr
VOC	24 lb/yr
CO	190 lb/yr
PM_{10}	22 lb/yr
SO_X	28 lb/yr

VII. CALCULATIONS (Continued):

D. Increase in Permitted Emissions (IPE):

1. Daily Increase in Permitted Emissions

N-4597-1-0, N-4597-2-0, and N-4597-3-0

For a new emissions unit, the daily IPE is the proposed daily PE for that emissions unit. Please refer to section VII.C.2 of this document for the maximum daily PE for each unit.

2. Quarterly Increase in Permitted Emissions

N-4597-1-0, N-4597-2-0, and N-4597-3-0

For a new emissions unit, the quarterly IPE is the proposed quarterly PE for that emissions unit. Please refer to section VII.C.3 of this document for the maximum quarterly PE for each unit.

3. Annual Increase in Permitted Emissions

N-4597-1-0, N-4597-2-0, and N-4597-3-0

For a new emissions unit, the annual IPE is the proposed annual PE for that emissions unit. Please refer to section VII.C.4 of this document for the maximum annual PE for each unit.

4. Adjusted Increase in Permitted Emissions (AIPE)

N-4597-1-0, N-4597-2-0, and N-4597-3-0

District Rule 2201, section 4.3 defines AIPE as the difference between an emission unit's post-project potential to emit (PE2) and the emission unit's Historically Adjusted Potential to Emit (HAPE): AIPE = PE2 – HAPE. Since this is a new stationary source, HAPE = 0, and AIPE = PE2 for all pollutants. Refer to section VII.C.2 of this document for the post-project potential to emit for each unit. For reference purposes, the AIPE is summarized in the table below:

Adjusted Increase in Permitted Emissions (AIPE) (lb/day)						
Permit Unit	NO_X	VOC	CO	PM_{10}	SO_X	NH_3
N-4597-1-0	451.6	39.4	219.0	247.2	16.8	316.6
N-4597-2-0	451.6	39.4	219.0	247.2	16.8	316.6
N-4597-3-0	103.0	2.9	22.8	2.6	3.4	0

VII. CALCULATIONS (Continued):

5. Stationary Source Increase in Permitted Emissions (SSIPE)

Since this is a new stationary source, the Stationary Source Project Increase in Permitted Emissions (SSIPE) is equal to the Post-Project Stationary Source Potential to Emit (SSPE2). The SSIPE is summarized in the table below:

SSIPE (lb/yr)						
Permit Unit	NO_X	VOC	CO	PM_{10}	SO_X	NH_3
N-4597-1-0	153,460	13,356	71,620	82,400	5,600	105,520
N-4597-2-0	153,460	13,356	71,620	82,400	5,600	105,520
N-4597-3-0	858	24	190	22	28	0
Total	307,778	26,736	143,430	164,822	11,228	211,040

6. Contemporaneous Increase in Permitted Emissions (CIPE)

The only purpose of calculating CIPE is to determine whether the modification of an existing major source is a Title I modification. Since this is a new stationary source, it is not an existing major source, and CIPE calculations are not required at this time.

E. <u>Facility Emissions:</u>

1. Pre-Project Stationary Source Potential to Emit (SSPE1)

Since this is a new stationary source, the SSPE1 = 0 for all pollutants.

2. Post-Project Stationary Source Potential to Emit (SSPE2)

SSPE2 (lb/yr)					
Permit Number	NO_X	VOC	CO	PM_{10}	SO_X
N-4597-1-0	153,460	13,356	71,620	82,400	5,600
N-4597-2-0	153,460	13,356	71,620	82,400	5,600
N-4597-3-0	858	24	190	22	28
Total	307,778	26,736	143,430	164,822	11,228

3. Baseline Emissions (BE)

The purpose of BE calculations is to determine the baseline emissions for pollutants for which the facility was a major source prior to the modification. Since this a new stationary source, it is not necessary to determine the baseline emissions.

VIII. COMPLIANCE:

Rule 1080 *Stack Monitoring (12/17/92)*

This Rule grants the APCO the authority to request the installation and use of continuous emissions monitors (CEM's), and specifies performance standards for the equipment and administrative requirements for record keeping, reporting, and notification. The facility will be equipped with operational CEM's for NO_X, CO, and O_2. Provisions included in the operating permit are consistent with the requirements of this Rule. Compliance with the requirements of this Rule is anticipated.

Proposed Rule 1080 Conditions:

- 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 1080]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and compliance source testing are both performed, in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted along with quarterly compliance reports to the District. [District Rule 1080]

- Permittee 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 1080]

- Permittee shall submit a written report to the APCO for each calendar quarter, within 30 days of the end of the quarter, including: time intervals, data and magnitude of excess emissions; nature and cause of excess (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

VIII. COMPLIANCE (Continued):

Rule 1081 *Source Sampling (12/16/93)*

- This Rule requires adequate and safe facilities for using in sampling to determine compliance with emissions limits, and specifies methods and procedures for source testing and sample collection. The requirements of this Rule will be included in the operating permit. Compliance with this Rule is anticipated.

Proposed Rule 1081 Conditions:

- Exhaust stacks shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. [District Rule 1081]

- Source testing to demonstrate compliance with the NO_x, CO, and VOC short-term emission limits (lb/hr and ppmvd @ 15% O_2) shall be conducted within 60 days of initial operation of CTG and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

- Source testing to demonstrate compliance with PM_{10} emission limit (lb/hr) shall be conducted within 60 days of initial operation and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. If CTG is operated during the winter (December, January, or February) then additional testing shall be conducted within 30 days of such operation. [District Rule 1081]

- Source testing of startup NO_x, CO, VOC, and PM_{10} mass emission rates shall be conducted for one of the gas turbine engines (N-4597-1 or N-4597-2) upon initial operation and at least once every seven years thereafter by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm. CEM relative accuracy shall be determined during startup source testing in accordance with 40 CFR 60, Appendix B. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of CTG and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

- The District must be notified 30 days prior to any source testing, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source testing shall be submitted to the District within 60 days of testing. [District Rule 1081]

VIII. COMPLIANCE (Continued):

- The following test methods shall be used: PM_{10} – EPA method 5 (front half and back half); NO_x – EPA Methods 7E or 20; CO – EPA methods 10 or 10B; O_2 – EPA Methods 3, 3A, or 20; VOC – EPA methods 18 or 25; and fuel gas sulfur content – ASTM D3246. 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 1081, 4001, and 4703]

Rule 2201 *New and Modified Stationary Source Review Rule (08/20/01)*

A. BACT:

BACT Applicability

District Rule 2201, section 4.1 states that BACT is triggered for NO_x, VOC, SO_x, or PM_{10} from a new or modified emission unit if the project results in a unit having an AIPE greater than two pounds per day for that pollutant.

Section 4.2.1 states that for new or modified emission units, BACT is triggered for CO if the AIPE is greater than two pounds per day and $SSPE2_{CO}$ is 200,000 pounds per year or more.

N-4597-1-0 and N-4597-2-0 (Turbines)

As shown in section VII.D.4 of this document, AIPE for each unit exceeds 2.0 pounds per day for NO_x, VOC, CO, PM_{10}, SO_x, and NH_3.

However, as shown in section VII.E.2 of this document, $SSPE2_{CO}$ is less than 200,000 pounds per year. Therefore, BACT is not triggered for CO.

The AIPE of ammonia is greater than two pounds per day. However, the ammonia emissions are intrinsic to the operation of the SCR system, which is BACT for NO_x. The emissions from a control device that is determined by the District to be BACT are not subject to BACT.

Therefore, BACT is triggered for NO_x, VOC, SO_x, and PM_{10}.

N-4597-3-0 (Emergency IC engine)

As shown in section VII.D.4 of this document, AIPE for this unit exceeds 2.0 pounds per day for NO_x, VOC, CO, PM_{10}, and SO_x.

VIII. COMPLIANCE (Continued):

However, as shown in section VII.E.2 of this document, $SSPE2_{CO}$ is less than 200,000 pounds per year. Therefore, BACT is not triggered for CO.

Therefore, BACT is triggered for NO_x, VOC, SO_x, and PM_{10}.

BACT Guidance and Top-Down BACT Analyses:

N-4597-1-0 and N-4597-2-0 (Turbines)

Per District BACT Policy APR 1305 (11/09/99), a Top-Down BACT analysis shall be performed as a part of the application review for each emission unit subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse currently contains BACT Guideline 3.4.7, which is applicable to simple cycle, large frame industrial turbines rated greater than or equal to 150 MW. The turbines proposed for this project are simple cycle, large frame industrial turbines. However, each proposed turbine is rated at 84.4 MW. Therefore, pursuant to the District's BACT policy, a top down BACT analysis will be performed to **revise** BACT Guideline 3.4.7 to change the equipment rating to include simple cycle, industrial frame turbines greater than or equal to 50 MW (see Appendix ?).

The CTG's meet District BACT requirements (see top down BACT analysis in Appendix ?) for all affected pollutants, as summarized below:

NO_X: 5.0 ppmvd @ 15% O_2 (3 hr rolling avg.) - except during startup/shutdown.

VOC: 2.0 ppmvd @ 15% O_2 (3 hr rolling avg.) - except during startup/shutdown.

PM_{10}: air inlet cooler/filter, lube oil vent coalescer to achieve less than 5% opacity visible emissions at lube oil vents, and natural gas as fuel.

SO_X: natural gas fuel with a sulfur content not exceeding 0.75 grains of sulfur compounds (as S) per 100 dry scf of natural gas.

N-4597-3-0 (Emergency IC engine)

The District's Best Available Control Technology (BACT) Clearinghouse (3rd Quarter, 2001) guideline 3.1.2 applies to emergency diesel IC engines rated greater than or equal to 175 bhp but less than 400 bhp. For source categories or classes covered in the BACT Clearinghouse, relevant information under each of the steps may be simply cited from the Clearinghouse without further analysis.

VIII. COMPLIANCE (Continued):

The unit meets District BACT requirements (see top down BACT analysis in Appendix ?) for all affected pollutants, as summarized below:

NO_X: 6.9 g/bhp-hr or less.
VOC: Positive crankcase ventilation system.
PM_{10}: 0.1 g/bbp-hr (if TBACT is triggered); 0.4 g/bhp-hr (if TBACT not triggered).
SO_X: Diesel fuel with a sulfur content not exceeding 0.05% by weight.

B. Offsets:

Offset Applicability:

Offsets are examined on a pollutant by pollutant basis, and are triggered for any pollutant with a SSPE2 in equal to or greater than the values in section 4.5.3. As shown in section VII.E.2 of this document, the SSPE2 of each pollutant is:

Pollutant	Offset Thresholds (lb/yr)	SSPE2 (lb/yr)	Offsets Required?
NO_x	20,000	306,920[9]	**Yes**
VOC	20,000	26,712[9]	**Yes**
CO	200,000	143,240[9]	No
PM_{10}	29,200	164,800[9]	**Yes**
SO_x	54,750	11,200[9]	No

As shown in the table above, the SSPE2 for NO_x, VOC, and PM_{10} is the respective offset trigger threshold. Therefore, offsets are triggered for NO_x, VOC, and PM_{10}.

Quantity of Offsets Required:

Since this is a new stationary source, the SSPE1 for each pollutant is 0. Pursuant to District Rule 2201, section 4.7.2.1 the offset quantity will be the difference between the Post-Project Potential to Emit (PPE) of all new and modified units and the offset trigger levels, as summarized in the table below:

Pollutant	SSPE2 (lb/yr)	Offset Thresholds (lb/yr)	Offset Quantities Required (lb/yr)	Offset Quantities Required (lb/qtr)
NO_x	306,920	20,000	286,920	**71,730**
VOC	26,712	20,000	6,712	**1,678**
PM_{10}	164,800	29,200	135,600	**33,900**

[9] The emission contributions from N-4597-3-0 is subtracted from the SSPE2 because emergency equipment is exempt from offset requirements per District Rule 2201, section 4.6.2.

VIII. COMPLIANCE (Continued):

Interpollutant Offset Ratio:

The applicant stated that PM_{10} emission reduction credits, in the quantity necessary to mitigate the proposed PM_{10} increases, were unavailable. Consequently, other means of satisfying District offset requirements were explored. In order to satisfy District offset requirements the applicant has proposed providing SO_x reductions in place of PM_{10} reductions. District Rule 2201 section 4.13.3 allows such interpollutant substitutions provided the applicant shows that the substitution will not cause or contribute to the violation of an ambient air quality standard in accordance with section 4.14.2 and that the appropriate interpollutant offset ratio is utilized.

Air quality impact modeling was performed, which showed that this project will not cause or contribute to the violation of an ambient air quality standard. A full discussion of this modeling is presented in section VIII (Air Quality Impact) of this evaluation.

As a result of negotiations with the District the applicant has provided an interpollutant offset ratio analysis showing that the appropriate interpollutant offset ratio is 2.0 pounds of SO_x per 1 pound of PM_{10}. This does not include the required distance ratio that is specified in District Rule 2201 section 4.2.4. Accounting for the distance of the reductions from the point of use, the overall interpollutant/distance offset ratio is 2.2 pounds of SO_x per 1 pound of PM_{10} if the reductions originated less than 15 miles from the point of use and 2.5 pounds of SO_x per 1 pound of PM_{10} if the reductions originated 15 miles or more from the point of use. Refer to Appendix ?? of this document for the detailed interpollutant offset analysis.

VIII. COMPLIANCE (Continued):

Quantity of Offsets Provided:

NO_x				
Source (location)	**Q1 (lb)**	**Q2 (lb)**	**Q3 (lb)**	**Q4 (lb)**
C-278-2 (Mendota, CA)	0	1,408	23,410	2,563
Value @ 1.5:1	**0**	**939**	**15,607**	**1,709**
Source "A" (Elk Hills, Kern Co.)	58,181.7	54,709.5	55,589.5	66,641.5
Value @ 1.5:1	**38,788**	**36,473**	**37,060**	**44,428**
N-244-2 (757 E. 11th St. in Tracy, CA)	0	0	38,207	0
Value @ 1.2:1	**0**	**0**	**31,839**	**0**
Source "B" (Oildale, CA)	6,119	24,384	14,386	6,858
Value @ 1.5:1	**4,079**	**16,256**	**9,591**	**4,572**
Source "C" (Coles Levee, Kern Co.)	3,614	4,047	3,267	3,646
Value @ 1.5:1	**2,409**	**2,698**	**2,178**	**2,431**
Total Provided	**45,276**	**56,366**	**96,275**	**53,140**
Total Required	71,730	71,730	71,730	71,730
Difference	-26,454	-15,364	24,545	-18,590
Q3 excess divided equally between Q1, Q2, and Q4	8,182	8,182	--	8,182
Balance Required	**-18,272**	**-7,182**	0	**-10,408**

In addition to those specified in the above table, the applicant must provide additional offsets in order to mitigate the increase in NO_x emissions. The permits will contain conditions requiring the applicant to provide sufficient offset quantities in accordance with District Rule 2201.

VOC				
Source (location)	**Q1 (lb)**	**Q2 (lb)**	**Q3 (lb)**	**Q4 (lb)**
S-1538-1 (Bakersfield, CA)	8,793.1	10,661.6	11,528	9,725
Value @ 1.5:1	**5,862.1**	**7,107.7**	**7,685.3**	**6,483.3**
Total Provided	**5,862.1**	**7,107.7**	**7,685.3**	**6,483.3**
Total Required	1,678	1,678	1,678	1,678
Difference	4,184.1	5,429.7	6,007.3	4,805.3
Balance Remaining on S-1538-1 (adjusted for 1.5:1 ratio)	6,276.2	8,144.6	9,011	7,208

VIII. COMPLIANCE (Continued):

PM_{10}				
Source (location)	**Q1 (lb)**	**Q2 (lb)**	**Q3 (lb)**	**Q4 (lb)**
S-1505-4 (Devil's Den Gin)	0	0	0	1,000
Value @ 1.5:1	**0**	**0**	**0**	**666.7**
N-226-4 (Third & C St. in Turlock, CA)	3,855	3,652	2,906	3,860
Value @ 1.5:1	**2,570**	**2,434.7**	**1,937.3**	**2,573.3**
C-394-4 (10833 S. Cornelia, Rasin City)	0	0	0	11,672
Value @ 1.2:1	**0**	**0**	**0**	**7,781.3**
C-382-4 (2691 S. Cedar in Fresno)	3,075	3,075	3,075	3,075
Value @ 1.5:1	**2,050**	**2,050**	**2,050**	**2,050**
S-1452-4 (217 W Terra Bella, Pixley)	0	0	0	12,372
Value @ 1.5:1	**0**	**0**	**0**	**8,248**
S-1442-4 (16351 Ave 40, Earlimart)	0	0	0	5078
Value @ 1.5:1	**0**	**0**	**0**	**3,385.3**
N-183-4 (4004 S. El Dorado, Stockton)	20,406	19,910	16,368	16,509
Value @ 1.5:1	**13,604**	**13,273.3**	**10,912**	**11,006**
N-256-5 (800 W. Church St, Stockton)	25,000	25,000	25,000	25,000
Value @ 2.5:1[10]	**10,000**	**10,000**	**10,000**	**10,000**
Source "D" (Stockton, CA)	100,000	100,000	100,000	100,000
Value @ 2.5:1[10]	**40,000**	**40,000**	**40,000**	**40,000**
Total Provided	**68,224**	**67,758**	**64,899.3**	**85,710.6**
Total Required	33,900	33,900	33,900	33,900
Difference	34,324	33,858	30,999.3	51,810.6
Balance Remaining on Source "D" (adjusted for 2.5:1 ratio)	85,810	84,645	77,498.3	129,526.5

[10] Since this ERC certificate is for SO_x emissions. An interpollutant offset ratio of 2.0 pounds of SO_x per 1.0 pound of PM10. Since the location of these reductions occurred greater than 15 miles from the proposed location, an additional distace ratio of 1.5:1 will be applied pursuant to District Rule 2201, section 4.2.4. Therefore, the total adjustment ratio is (2.0:1)(1.5:1) = 2.5:1.

VIII. COMPLIANCE (Continued):

C. Public Notification:

1. Applicability

District Rule 2201, section 5.4, requires a public notification for the affected pollutants from the following types of projects:

- New Major Sources
- Title I modifications
- New emission units with a PE > 100 lb/day of any one pollutant (IPE Notifications)
- Modifications with SSPE1 below an offset threshold and SSPE 2 above an offset threshold on a pollutant by pollutant basis (Existing Facility Offset Threshold Exceedence Notification)
- New stationary sources with SSPE2 exceeding offset thresholds (New Facility Offset Threshold Exceedence Notification)
- Any permitting action with a SSIPE exceeding 20,000 lb/yr for any one pollutant. (SSIPE Notice)

a. New Major Source Notice Determination:

Pollutant	Major Source Thresholds (lb/yr)	SSPE2 (lb/yr)	Major Source?
NO_x	100,000	307,778	**Yes**
VOC	100,000	26,736	No
CO (in CO attainment areas)	200,000	143,430	No
PM_{10}	140,000	164,822	**Yes**
SO_x	140,000	11,228	No

As shown in the table above, the proposed project results in increases in NO_x and PM_{10} emissions in excess of the major source thresholds listed in Table 3-2 of District Rule 2201. Therefore, a public notice is required per Rule 2201, section 5.4.1 because the facility will be a new major source for NO_x and PM_{10} emissions.

b. Title I Modification Notice Determination:

For facilities that are non-major sources prior to the modification, a Title I modification is triggered if the post project stationary source potential to emit (SSPE2) is increased to levels above the thresholds listed in Table 3-4 of District Rule 2201.

VIII. COMPLIANCE (Continued):

Pollutant	Title I Modification Thresholds (lb/yr)	SSPE2 (lb/yr)	Title I Modification?
NO_x	100,000	307,778	**Yes**
VOC	100,000	26,736	No
CO (in CO attainment areas)	200,000	143,430	No
PM_{10}	140,000	164,822	**Yes**
SO_x	140,000	11,228	No

Since this is a new stationary source, this facility was not a major source for any pollutants prior to the proposed project. As shown in the above table, SSPE2 for NO_x and PM_{10} emissions will exceed the Title I Modification thresholds in Table 3-4 of District Rule 2201. Therefore, a Title I Modification is required for NO_x and PM_{10} emissions only.

c. PE Notification:

A notification is required for each new emission unit with the potential to emit more than 100 pounds per day of any one affected pollutant. The potentials to emit for each unit are summarized in the tables below.

N-4597-1-0 and N-4597-2-0 (Turbines)

N-4597-1-0: Post-Project Potential to Emit						
Permit Unit	NO_x (lb/day)	VOC (lb/day)	CO (lb/day)	PM_{10} (lb/day)	SO_x (lb/day)	NH_3 (lb/day)
N-4597-1-0	451.6	39.4	219.0	247.2	16.8	316.6
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	**Yes**	No	**Yes**	**Yes**	No	**Yes**

N-4597-2-0: Post-Project Potential to Emit						
Permit Unit	NO_x (lb/day)	VOC (lb/day)	CO (lb/day)	PM_{10} (lb/day)	SO_x (lb/day)	NH_3 (lb/day)
N-4597-2-0	451.6	39.4	219.0	247.2	16.8	316.6
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	**Yes**	No	**Yes**	**Yes**	No	**Yes**

The potentials to emit for NO_x, CO, PM_{10}, and NH_3 from these units exceed 100 pounds per day. Therefore, a notification is required for NO_x, CO, PM_{10}, and NH_3 emissions.

VIII. COMPLIANCE (Continued):

N-4597-3-0 (Emergency IC engine)

N-4597-3-0: Post-Project Potential to Emit						
Permit Unit	NO_X (lb/day)	VOC (lb/day)	CO (lb/day)	PM_{10} (lb/day)	SO_X (lb/day)	NH_3 (lb/day)
N-4597-3-0	103.0	2.9	22.8	2.6	3.4	0
Threshold (lb/day)	100	100	100	100	100	100
Notification Required?	**Yes**	No	No	No	No	No

The potential to emit for NO_X from this unit exceeds 100 pounds per day. Therefore, a notification is required for NO_X emissions.

d. Existing Facility Offset Threshold Exceedence Notification

This is not an existing facility. This section does not require a public notification.

e. New Facility Offset Threshold Exceedence Notification

Since this is a new stationary source, the SSPE1 for all pollutants is below the offset thresholds. As shown in section VII.E.2 of this document, the SSPE2 for NO_x, VOC, and PM_{10} emissions will exceed the offset thresholds. Therefore, a public notification is required for NO_x, VOC, and PM_{10} emissions.

f. SSIPE Notification:

A notification is required for any permitting action that results in a SSSIPE of more than 20,000 lb/yr of any affected pollutant. As shown in section VII.D.5 of this document, the SSIPE for NO_x, VOC, CO, PM_{10}, and NH_3 will be more than 20,000 pounds per year. Therefore, a SSIPE notification is required for NO_x, VOC, CO, PM_{10}, and NH_3.

2. Public Notice Requirements

In summary, public notification is required for NO_x, VOC, CO, PM_{10}, and NH_3 emissions. The required notices will be conducted in accordance with Rule 2201 section 5.5. The notices will run concurrently.

VIII. COMPLIANCE (Continued):

C. Daily Emission Limits:

N-4597-1-0 and N-4597-2-0 (Turbines)

- The NOx emissions shall not exceed 451.6 pounds per day.
- The NOx emissions during steady state operation shall not exceed 5.0 ppmvd @ 15% O_2 over a three hour averaging period. Steady-state period refers to any period that is not a start-up or shutdown period.
- The VOC emissions shall not exceed 39.4 pounds per day.
- The VOC emissions during steady state operation shall not exceed 2.0 ppmvd, as methane, @ 15% O_2. Steady-state period refers to any period that is not a start-up or shutdown period.
- The CO emissions shall not exceed 219.0 pounds per day.
- The CO emissions during steady state operation shall not exceed 6.0 ppmvd @ 15% O_2. Steady-state period refers to any period that is not a start-up or shutdown period.
- The PM10 emissions shall not exceed 0.0112 lb/MMBtu of fuel consumption.
- The SOx emissions shall not exceed 0.00071 lb/MMBtu of fuel consumption.
- The ammonia emission concentration shall not exceed 10 ppmvd @ 15% O_2.

N-4597-3-0 (Emergency IC engine)

- NOx emissions shall not exceed 5.09 g/hp-hr.
- VOC emissions shall not exceed 0.14 g/hp-hr.
- CO emissions shall not exceed 1.13 g/hp-hr.
- PM10 emissions shall not exceed 0.13 g/bhp-hr based on U.S EPA certification using ISO 8178 test procedure.

VIII. COMPLIANCE (Continued):

- Only CARB-certified diesel fuel containing not more than 0.05% sulfur by weight shall be used.

D. Air Quality Impact Analysis:

Section 4.14.2 of this Rule requires that an air quality impact analysis (AQIA) be conducted for the purpose of determining whether the operation of the proposed equipment will cause or make worse a violation of an air quality standard. The required analysis was conducted by the Technical Services Division of the SJVAPCD. Refer to Appendix ?? of this document for the AQIA summary sheet.

The proposed location is in an attainment area for NOx, CO and SOx. As shown by the AQIA summary sheet the proposed equipment will not cause a violation of an air quality standard for NOx, CO or SOx.

The proposed location is located in a non-attainment area for PM10. The increase in the ambient PM10 concentration due to the proposed equipment is shown on the table titled Calculated Contribution. The levels of significance, from 40 CFR Part 51.165 (b)(2), are shown on the table titled Significance Levels.

Significance Levels					
Pollutant	Significance Levels ($\mu g/m^3$) - 40 CFR Part 51.165 (b)(2)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	5	N/A	N/A	N/A

Calculated Contribution					
Pollutant	Calculated Contributions ($\mu g/m^3$)				
	Annual Avg.	24 hr Avg.	8 hr Avg.	3 hr Avg.	1 hr Avg.
PM_{10}	1.0	4.35	N/A	N/A	N/A

As shown, the calculated contribution of PM_{10} will not exceed the EPA significance level. This project is not expected to make worse a violation of an air quality standard.

VIII. COMPLIANCE (Continued):

F. Compliance Assurance

1. Source Testing

N-4597-1-0 and N-4597-2-0 (Turbines)

District Rule 4703 requires NO_x and CO emission testing as well as percent turbine efficiency testing on an annual basis. The District Source Test Policy (APR 1705 10/09/97) requires annual testing for all pollutants controlled by catalysts. The control equipment will include a SCR system and an oxidation catalyst. Ammonia slip is an indicator of how well the SCR system is performing and PM_{10} emissions are a good indicator of how well the inlet air cooler/filter are performing.

Therefore, initial source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be performed within 60 days of initial operation. Annual compliance source testing for NO_X, VOC, CO, PM_{10}, and ammonia slip will be required thereafter.

Also, initial source testing of NO_X, CO, and PM_{10} startup emissions for one gas turbine engine will be required initially and not less than every seven years thereafter. This testing will serve two purposes, to validate the startup emission estimates used in the emission calculations and to verify that the CEM's accurately measure startup emissions.

Each CTG will have a separate exhaust stack. The units will be equipped with CEM's for NO_X, CO, and O_2. Each CTG will be equipped with an individual CEM. Each CEM will have two ranges to allow accurate measurements of NO_X and CO emissions during startup. The CEM's must meet the installation, performance, relative accuracy, and quality assurance requirements specified in 40 CFR 60.13 and Appendix B (referenced in the CEM requirements of Rule 4703) and the acid rain requirements in 40 CFR part 75.

40 CFR Part 60 subpart GG requires fuel nitrogen content testing. The District will accept the NO_x source testing required by District Rule 4703 as equivalent to fuel nitrogen content testing.

40 CFR Part 60 subpart GG requires that fuel sulfur content be monitored. Refer to the monitoring section of this document for a discussion of the fuel sulfur testing requirements.

N-4597-3-0 (Emergency IC engine)

Source testing is not typically required for emergency diesel-fired IC engines.

VIII. COMPLIANCE (Continued):

2. Monitoring

N-4597-1-0 and N-4597-2-0 (Turbines)

Monitoring of NO_x emissions is required by District Rule 4703. The applicant has proposed a CEMS for NO_x.

CO monitoring is not specifically required by any applicable Rule or Regulation. Nevertheless, due to erratic CO emission concentrations during start-up and shutdown periods, it is necessary to limit the CO emissions on a pound per hour basis. Therefore, a CO CEMS is necessary to show compliance with the CO limits of this permit. The applicant has proposed a CO CEMS.

District Rule 4703 requires the facility to monitor the SCR system ammonia injection rate. Ammonia injection rate monitoring will be required.

District Rule 4703 requires the facility to monitor the exhaust temperature and exhaust flow rate. Exhaust temperature and exhaust flow rate monitoring will be required.

District Rule 4703 requires that the elapsed time of operation, on an annual basis be monitored. Such monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel consumption. Fuel consumption monitoring will be required.

40 CFR Part 60 Subpart GG requires monitoring of the fuel nitrogen content. As stated in the Subpart GG compliance section of this document, the District will allow the annual NO_x source test to substitute for this requirement.

40 CFR Part 60 Subpart GG requires monitoring of the fuel sulfur content. The gas supplier, Pacific Gas and Electric Company, may deliver gas with a sulfur content of up to 1.0 gr/scf. Since the sulfur content of the natural gas would not exceed this value, it is District practice to require only annual fuel sulfur content testing if the SO_x emission factor is based on a fuel sulfur content of 1.0 gr/scf. The applicant is proposing a SO_x emission factor based on a fuel sulfur content of 0.25 gr/scf. For such units, fuel sulfur content testing is required more frequently. The facility will be required to test fuel sulfur content weekly until eight consecutive tests show compliance. After that, the testing frequency may be reduced to quarterly. If a quarterly test fails to show compliance then the testing returns to weekly until eight consecutive weekly tests show compliance. After that, the testing frequency may return to quarterly.

VIII. COMPLIANCE (Continued):

N-4597-3-0 (Emergency IC engine)

No monitoring is required.

3. Record Keeping

N-4597-1-0 and N-4597-2-0 (Turbines)

The applicant will be required to keep records of all of the parameters that are required to be monitored. Refer to section VIII.F.2 of this document for a discussion of the parameters that will be monitored.

N-4597-3-0 (Emergency IC engine)

The applicant will be required to keep records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be made available for District inspection upon request for a period of two years.

4. Reporting

40 CFR Part 60 Subpart GG requires that the facility report the use of fuel with a sulfur content of more than 0.8% by weight. Such reporting will be required.

40 CFR Part 60 Subpart GG requires the reporting of exceedences of the NO_x emission limit of the permit. Such reporting will be required.

VIII. COMPLIANCE (Continued):

Rule 2520 *Federally Mandated Operating Permits (06/15/95)*

This project will be subject to Rule 2520 (Title V) because it meets the following criteria specified in section 2.0:

- a major source of NO_X,
- potential to emit greater than 100 ton/year (for NO_x),
- CTG's are subject to NSPS,
- subject to Title IV Acid rain program

Pursuant to Rule 2520, section 5.3.1, Tracy Peaker Project must submit a Title V application within 12 months of commencing operations. No action is required at this time.

Rule 2540 *Acid Rain Program (11/13/97)*

The proposed CTG's are subject to the acid rain program as phase II units, i.e. they will be installed after 11/15/90 and each has a generator nameplate rating greater than 25 MW.

The acid rain program will be implemented through a Title V operating permit. 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 unit expects to generate electricity. The facility anticipates beginning commercial operation in the 2^{nd} or 3^{rd} quarter of 2001.

The acid rain program requirements for this facility are relatively minimal. Monitoring of the NO_X and SO_X emissions and a relatively small quantity of SO_X allowances (from a national SO_X allowance bank) will be required as well as the use of a NO_X CEM.

Rule 4001 *New Source Performance Standards, 40 CFR 60 – Subpart GG*

N-4597-1-0 and N-4597-2-0 (Turbines)

The proposed CTG's are subject to Subpart GG, which limits oxides of nitrogen and sulfur from stationary gas turbines. The applicable NO_x limit specified in section 60.332 (a) (1), one hour average, is as follows:

$$NO_X \text{ (\% by volume @ 15\% } O_2) = 0.0075 \times (14.4 \div Y) + F$$

VIII. COMPLIANCE (Continued):

Where:

Y = manufacturer's rated heat rate at rated peak load (kJ/watt hour), or actual measured heat rate at lhv and peak load. Y shall not exceed 14.4 kJ/watt hour. As these CTG's are not yet built, it is not possible to determine the actual heat rate.

F = NO_X emission allowance for fuel bound nitrogen. Natural gas typically has no fuel bound nitrogen, so F is set equal to 0.

Please note that the NSPS NO_X standard occurs at the maximum heat rate (depending on ambient temperature) at full load.

NSPS NO_x limit:

Y = max heat rate @ lhv = 10,500 Btu/kW hr (peak load @ 59 °F)
= 10.500 Btu/W hr × 1.0542 kJ/Btu
Y = 11.0691 kJ/W hr (less than 14.4 kJ/W hour)

NO_x (% by vol @ 15% O_2) = 0.0075 × (14.4 ÷ 11.0691) + 0
= 0.00976
= 97.6 ppmv @ 15% O_2

The CTG's will operate at a BACT NO_x level of 5.0 ppmvd @ 15% O_2, except during startup and shutdown, on a three hour average. Since the proposed NO_x emission concentration for each CTG is significantly less than the NSPS limit, compliance with the Subpart GG NO_x standard (one-hour average) is expected.

The applicable SO_X limits specified in section 60.333 are as follows:

SO_X = 0.015% by vol @ 15% O_2
= 150 ppmv @ 15% O_2

or fuel S ≤ 0.8% by weight.

The 150 ppmv @ 15% O_2 limit specified in section 60.333, paragraph (a) is equivalent to 0.769 lb-SO_X/MMBtu as follows:

$$\frac{(150\text{ ppmvd})\times\left(8{,}578\frac{\text{ft}^3}{\text{MMBtu}}\right)\times\left(64\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)\times\left(\frac{20.9}{20.9-15}\right)}{\left(379.5\frac{\text{ft}^3}{\text{lb}-\text{mol}}\right)\times\left(10^6\right)} = 0.769\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

VIII. COMPLIANCE (Continued):

SO_X emissions are based on combusting natural gas with a fuel sulfur content of 0.25 gr/100 scf, which results in an emission rate of 0.00071 lb-SO_x/MMBtu. The percent sulfur by weight of natural gas of 0.25 gr-S/100 scf natural gas is 0.000842, determined as follows (assuming a 100 scf sample comprised of methane at 60 °F):

$$\left(\frac{0.25\,\text{gr} - \text{S}}{100\,\text{ft}^3 - \text{NG}}\right) \times \left(\frac{\text{lb} - \text{S}}{7000\,\text{gr} - \text{S}}\right) \times \left(\frac{\text{ft}^3 - \text{NG}}{0.0424\,\text{lb} - \text{NG}}\right) = 8.42 \times 10^{-6} \frac{\text{lb} - \text{S}}{\text{lb} - \text{NG}}$$

Both SO_x emissions and fuel sulfur content are less than that required by Subpart GG. Record keeping and reporting of the fuel sulfur content is required as specified in section 60.334 (b)(2). Reporting will be performed using an alternative custom reporting schedule. Because the CTG's will not use water injection, monitoring of water injection rate is not applicable and not required.

Reporting and notifications, and initial compliance testing will be required as specified in 40 CFR, Subpart A. Compliance is expected.

N-4597-3-0 (Emergency IC engine)

This unit is not subject to the requirements of this Subpart.

Rule 4101 *Visible Emissions (12/17/92)*

N-4597-1-0 and N-4597-2-0 (Turbines)

The CTG's including lube oil vents will be limited by permit condition to not have visible emissions, except for three minutes in any hour, greater than 5% opacity as a BACT requirement. This is more restrictive than the 20% opacity limit in Rule 4101 (which also has an exemption for up to 3 minutes in any hour). Compliance is expected.

N-4597-3-0 (Emergency IC engine)

Based on experience with similar operations, compliance with visible emission limits is expected under normal operating conditions.

VIII. COMPLIANCE (Continued):

Rule 4102 *Nuisance (12/17/92)*

A. California Health & Safety Code 41700 (Health Risk Analysis)

The District's Risk Management Policy requires an evaluation of the risk associated with increases in hazardous air pollutants. Pursuant to the definition of Section V.A. of this policy, a hazardous pollutant is "...a substance included in lists prepared by the California Air Resources Board pursuant to Section 44321 of the California Health and Safety Code that have OEHHA approved health risk values and all pollutants listed in section 112(b) of the Federal Clean Air Act...". An increase of potentially hazardous air pollutants is expected; therefore, an evaluation of the associated health risk is required.

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices were less than 1.0 and the cancer risk was less than one in a million. Under the District's risk management policy, Policy TOX 1, TBACT is not required for any proposed emissions unit as shown in the table below:

SCREEN HRA SUMMARY			
	Turbine #1	Turbine #2	IC Engine
Acute Hazard Index	0.0	0.0	N/A
Chronic Hazard Index	0.0	0.0	N/A
70 yr Cancer Risk	0.0	0.0	0.3E-9
T-BACT Required?	**NO**	**NO**	**NO**

B. Discussion of Toxics BACT (TBACT)

TBACT is triggered if the cancer risk exceeds one in one million and if either the chronic or acute hazard index exceeds 1. The results of the health risk assessment show that none of the TBACT thresholds are exceeded. TBACT is not triggered.

The facility will be located on a nine-acre fenced site within a 40-acre parcel in a sparsely populated, unincorporated portion of western San Joaquin County. Nuisance complaints are not expected provided that the proposed equipment is properly maintained and operated. Therefore, proposed project is not expected to result in nuisance complaints.

<u>Proposed Rule 4102 Conditions</u>:

- No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

- During startup or shutdown of any combustion turbine generator(s), combined emissions from the two CTG's (S-3492-3 and '-4) shall not exceed the following: NOx – 145.24 lb and CO – 364.86 lb in any one hour. [CEQA]

VIII. COMPLIANCE (Continued):

Rule 4201 *Particulate Matter Concentration (12/17/92)*

Rule 4201 limits PM emissions from any source operation to 0.1 gr/dscf (standard conditions are 60 degrees F and 1 atmosphere pressure).

N-4597-1-0 and N-4597-2-0 (Turbines)

All PM emitted is expected to be 10 microns or smaller.

PM Emissions	=	10.3 lb/hr
Exhaust Stack H2O content	=	6.24%
Exhaust Gas Flow, scfm (wet)	=	638,232
Exhaust Gas Flow, dscfm	=	638,232 × [(100 – 6.24) ÷ 100] = 598,406

$$PM\left(\frac{gr}{dscf}\right) = \frac{\left(10.3\frac{lb-PM}{hr}\right)\times\left(\frac{hr}{60\,min}\right)\times\left(\frac{7000\,gr}{lb}\right)}{598{,}406\frac{dscf}{min}} = 0.002\frac{gr-PM}{dscf}$$

As shown above, PM emissions for the proposed CTG's will be less than 0.1 gr/dscf. Compliance is expected.

N-4597-3-0 (Emergency IC engine)

The particulate matter concentration in the engine's exhaust stream can be estimated as follows:

$$PM\left(\frac{gr}{dscf}\right) = \frac{\text{Emissions}\left(\frac{gr-PM}{min}\right)}{\text{Exhaust Flow }(scfm)\times\text{Moisture Correction}}$$

The applicant states that the exhaust flow rate is 655 dscfm. Assuming, as a conservative estimate, an exhaust moisture content of 10%, the particulate matter emission concentration at 60 °F is:

$$PM\left(\frac{gr}{dscf}\right) = \frac{0.11\frac{lb-PM}{hr}\times7000\frac{gr-PM}{lb-PM}\times\frac{hr}{60\ min}}{655\frac{ft^3}{min}\times\frac{1}{(1-0.1)}} = 0.018\frac{gr-PM}{dscf}$$

0.018 (gr/dscf) < 0.1(gr/dscf), therefore, compliance with this Rule is expected.

VIII. COMPLIANCE (Continued):

Rule 4202 *Particulate Matter Emission Rate (12/17/92)*

N-4597-1-0, N-4597-2-0, and N-4597-3-0

Rule 4202 establishes PM emission limits as a function of process weight rate in tons/hr. Gas and liquid fuels are excluded from the definition of process weight. Therefore, Rule 4202 does not apply to the proposed units.

Rule 4701 *Internal Combustion Engines (11/12/98)*

N-4597-1-0 and N-4597-2-0 (Turbines)

These units are not subject to the requirements of this Rule.

N-4597-3-0 (Emergency IC engine)

Since this unit is proposed as an emergency standby engine and it is limited to less than 200 hours per year of non-emergency operation, pursuant to section 4.2.1, it is exempt from the requirements of Rule 4701.

Rule 4703 *Stationary Gas Turbines (10/16/97)*

Rule 4703 limits NO_X and CO emissions from stationary gas turbines with ratings of greater than 0.3 megawatts.

N-4597-1-0 and N-4597-2-0 (Turbines)

NO_x Limit:

The proposed unit is rated at 10 MW or greater, will fire on natural gas, will be permitted to operate more than 877 hours per year and will utilize SCR. Per 5.1.1 of this Rule, the NO_x emissions must be limited utilizing the following equation:

$$NO_x \text{ Limit @ } 15\%\ O_2 = 9\left(\frac{EFF}{25}\right)$$

Where EFF is the higher of EFF_1 or EFF_2 where:

$$EFF_1 = \frac{3{,}412\ \frac{Btu}{kW-hr}}{\text{Actual Heat Rate @ HHV } \left(\frac{Btu}{kW-hr}\right)} \times 100\text{, and } EFF_2 = EFF_{MFR}\frac{LHV}{HHV}$$

VIII. COMPLIANCE (Continued):

EFF_1 Calculation:

Manufacturer's data indicates that the Actual Heat Rate @ HHV is 11,651 Btu/KW-hr. Therefore:

$$EFF_1 = \frac{3{,}412 \frac{Btu}{kW-hr}}{11{,}651 \frac{Btu}{kW-hr}} \times 100 = 29.3\%$$

EFF_2 Calculation:

No data is available for the manufacturer's continuous rated percent efficiency for each turbine. Therefore EFF_1 will be used for the calculation.

NO_x Limits:

$$NO_x \text{ limit utilizing } EFF_1 = 9\left(\frac{29.3}{25}\right) = 10.6 \text{ ppmvd @ } 15\%\ O_2$$

The applicant is proposing a NO_x emission concentration of 5.0 ppmvd @ 15% O_2 for each CTG. Compliance with the NO_x emission concentration limit of this Rule is expected.

CO Limit:

Per section 5.2, General Electric Frame 7 units must be limited to a CO emission concentration of 25 ppmv @ 15% O_2. The applicant is proposing a CO emission concentration limit of 6.0 ppmvd @ 15% O_2. Compliance with the CO emission concentration limit of this Rule is expected.

Monitoring and record keeping:

Rule 4703 requires that the operator install equipment that monitors the control system operating parameters, the elapsed time of operation, and a NO_X CEM that meets the requirements in 40 CFR Part 60 Appendix B, Spec 2 and the operator to maintain such records for at least two years. Prior to issuance of a Permit to Operate, the facility must submit information that correlates the control system operating parameters to the NO_x emission rate, to be used when the CEM is down or not operating properly, as required by section 6.2.3 of Rule 4703.

VIII. COMPLIANCE (Continued):

The facility must maintain a stationary gas turbine system operating log that includes, on a daily basis, the actual local time, start-up and stop time, length and reason for reduced load periods, total hours of operation, and the type and quantity of fuel used as required by Rule 4703, section 6.2.4. This information shall be available for inspection at any time for two years from the date of entry.

The facility must demonstrate compliance annually with the NO_X and CO emission limits and determine the demonstrated percent efficiency (EFF) of the stationary gas turbine, using the following test methods:

- Oxides of nitrogen emissions for compliance tests shall be determined by using EPA Method 7E or EPA Method 20.
- Carbon monoxide emissions for compliance tests shall be determined by using EPA Test Methods 10 or 10B.
- Oxygen content of the exhaust gas shall be determined by using EPA Methods 3, 3A, or 20.
- HHV and LHV of gaseous fuels shall be determined by using ASTM D3588-91, ASTM 1826-88, or ASTM 1945-81.

Demonstrated percent efficiency of the stationary gas turbine shall be determined using the facility instrumentation for gas turbine fuel consumption and power output. Power output values used to determine gas turbine efficiency shall be the electrical power output of the gas turbine. Compliance is expected.

N-4597-3-0 (Emergency IC engine)

These units are not subject to the requirements of this Rule.

Rule 4801 *Sulfur Compounds (12/17/92)*

N-4597-1-0 and N-4597-2-0 (Turbines)

CTG SO_X emissions are based on combusting natural gas consisting principally of methane with a fuel sulfur content of 0.25 gr/100 scf. This fuel sulfur content results in a SO_X emission factor of 0.00071 lb/MMBtu. Rule 4801 limits sulfur compound emissions to 0.2% by volume, dry (2,000 ppmvd), which is equivalent to an emission factor of 10.25 lb-SO_x/MMBtu as shown below.

VIII. COMPLIANCE (Continued):

$$\frac{(2{,}000\ \text{ppmvd})\times\left(8{,}578\,\frac{\text{ft}^3}{\text{MMBtu}}\right)\times\left(64\,\frac{\text{lb}-\text{SO}_x}{\text{lb}-\text{mol}}\right)\times\left(\frac{20.9}{20.9-15}\right)}{\left(379.5\,\frac{\text{ft}^3}{\text{lb}-\text{mol}}\right)\times\left(10^6\right)} = 10.25\,\frac{\text{lb}-\text{SO}_x}{\text{MMBtu}}$$

Therefore, SO_x emissions are not expected to exceed 2000 ppmvd, and compliance is expected.

N-4597-3-0 (Emergency IC engine)

Sulfur compound emissions (as SO_2) are not expected to exceed 0.2% by volume since the fuel sulfur content shall not exceed 0.05% by weight. Calculations are shown below:

lb-SO_2/gallon: $0.05\%\times 7.1\,\frac{\text{lb}}{\text{gal}}\times\frac{64\ \text{lb}-\text{SO}_2}{32\ \text{lb}-\text{S}} = 0.007\,\frac{\text{lb}-\text{SO}_2}{\text{gal}}$

lb-SO_2/exhaust volume: $\dfrac{\frac{\text{lb}-\text{SO}_2}{\text{gal}}}{(\text{F}-\text{factor})\times(\text{fuel heating value})}$

$$\frac{0.007\,\frac{\text{lb}-\text{SO}_2}{\text{gal}}}{9{,}051\,\frac{\text{dscf}}{\text{MMBtu}}\times 0.14\,\frac{\text{MMBtu}}{\text{gal}}} = 5.5\times10^{-6}\,\frac{\text{lb}-\text{SO}_2}{\text{dscf}}$$

Volume SO_2 = nRT/P

where: n = moles SO_2
T (standard temperature) = 60 °F = 520 °R
R (universal gas constant) = 10.73 psi-ft^3/lb-mol-°R
P (standard atmospheric) = 14.7 psia

$$\frac{5.5\times10^{-6}\,\frac{\text{lb}-\text{SO}_2}{\text{dscf}}}{64\,\frac{\text{lb}-\text{SO}_2}{\text{lb}-\text{mol}}} = 8.6\times10^{-8}\,\frac{\text{lb}-\text{mol}}{\text{dscf}}$$

$$\frac{\left(8.6\times10^{-8}\,\frac{\text{lb}-\text{mol}}{\text{dscf}}\right)\times\left(10.73\,\frac{\text{psia}-\text{dscf}}{\text{lb}-\text{mol}-\text{R}}\right)\times(520\ \text{R})}{14.7\ \text{psia}} \cong 3.3\times10^{-5}\,\frac{\text{dscf}}{\text{dscf exhaust}}$$

VIII. COMPLIANCE (Continued):

≅ 33 ppmv << 2000 ppmv. Therefore the engine is expected to operate in compliance with Rule 4801.

Rule 8010 *Fugitive Dust Administrative Requirements for Control of PM10 (04/25/96)*

The purpose of this Rule is to set forth the definitions, exemptions, requirements, administrative requirements, and fees applicable to all Rules in Regulation VIII.

Rule 8020 *Fugitive Dust Requirements for Control of PM10 From Construction, Demolition, Excavation, and Extraction Activities (04/25/96)*

The purpose of this Rule is to limit fugitive dust emissions from construction, demolition, excavation, and related activities. It requires the use of reasonably available control measures (RACM), as defined in Rule 8010, to maintain visible dust emissions (VDE) under the 40% opacity requirement.

The Tracy Peaker Project will commit to implementing RACM via the use of dust control measures (e.g., water, approved chemical stabilizers, etc.) during construction to maintain opacity to a level below 40% per Rule 8020 requirements.

California Environmental Quality Act (CEQA)

The California Energy Commission (CEC) is the lead Agency for CEQA. Generally, the District cannot make its final decision on ATCs until CEQA has been satisfied. For power generating projects that qualify for expedited processing (per District policy). The ATC's will be issued if the District's analysis and public notice is completed prior to CEQA approval. If the ATC's are issued prior to CEQA approval, the ATC's will include the following condition:

The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA).

California Health & Safety Code, Section 42301.6 School Notice

The facility is not with 1,000 feet of a K-12 school. A School notice is not required

VIII. COMPLIANCE (Continued):

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

A health risk screening assessment was performed for the proposed project. The acute and chronic hazard indices are less than 1.0 and the cancer risk is less than one in a million, which are the thresholds of significance for toxic air contaminants. This project qualifies for exemption per the above exemption criteria.

IX. RECOMMENDATION:

Issue the Preliminary Determination of Compliance for the facility subject to the proposed conditions presented in Attachment A.

X. BILLING INFORMATION:

Permit Unit	Rating	Fee Schedule	Previous Fee Schedule
N-4597-1-0	84,400 kW	3020-08B-G	None – new unit
N-4597-2-0	84,400 kW	3020-08B-G	None – new unit
N-4597-3-0	382 bhp	3020-10-C	None – new unit

ATTACHMENT A

PROPOSED CONDITIONS

EQUIPMENT DESCRIPTION, UNIT N-4597-1-0:
84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #1 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

- The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001]

- {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

- Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- CTG exhaust shall be equipped with continuously recording emissions monitor(s) dedicated to this unit for NO_x, CO, and O_2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM 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 2201, 4001, and 4703]

- The gas turbine engine shall be equipped with a continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 4001, and 4703]

- The CEM for NO_x and O_2 shall meet the applicable performance specification requirements in 40 CFR, Part 51, Appendix P and Part 60, appendix B, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the Environmental Protection Agency. [District Rule 1080]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing was performed in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted to the District along with quarterly compliance reports. [District Rule 1080]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]

- All equipment shall be maintained in proper operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

- The permittee shall monitor and record the NO_x emission rate, the CO emissions rate, the ammonia injection rate, the exhaust temperature, the exhaust oxygen content, and the exhaust flow rate. [District Rule 4703 and 4001]

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- The exhaust stack shall be equipped with permanent provisions for stack gas sample collection. 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. [District Rule 1081]

- A selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. Permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- This unit shall exclusively burn only natural gas with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

- During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (N-4597-1 and N-4597-2) shall not exceed the following: NO_x - 26 lb and CO - 42 lb in any one hour. [California Environmental Quality Act]

- Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup of the CTG shall not exceed a time period of 20 minutes each per occurrence. Shutdown of the CTG shall not exceed a time period of 30 minutes each per occurrence. Startup and shutdown events shall not exceed 250 occurrences per calendar year and once per day. [District Rule 2201]

- Operation of this unit shall not exceed 8,000 hours per calendar year. [District Rule 2201]

- Emissions from this unit, except during startup and shutdown events, shall not exceed any of the following: NO_x (as NO_2) - 25.25 lb/hr and 5.0 ppmvd @ 15% O_2; VOC - 2.33 lb/hr and 2.0 ppmvd @ 15% O_2; CO - 20.09 lb/hr and 6.0 ppmvd @ 15% O_2; PM_{10} - 10.3 lb/hr; and SO_x (as SO_2) - 0.70 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emissions from this unit shall not exceed any of the following: NO_x (as NO_2) - 451.6 lb/day; VOC - 39.4 lb/day; CO - 219.0 lb/day; PM_{10} - 247.2 lb/day; and SO_x (as SO_2) - 16.8 lb/day. [District Rule 2201]

- Combined quarterly emissions from N-4597-1 and N-4597-2 shall be calculated for each calendar quarter and shall not exceed any of the following: NO_x (as NO_2) - Q1: 76,704 lb, Q2: 76,704 lb, Q3: 76,756 lb, and Q4: 76,756 lb; VOC - Q1: 6,676 lb, Q2: 6,676 lb, Q3: 6,680 lb, and Q4: 6,680 lb; and PM_{10} - Q1: 41,200 lb, Q2: 41,200 lb, Q3: 41,200 lb, and Q4: 41,200 lb. [District Rule 2201]

- Combined annual emissions from N-4597-1 and N-4597-2 calculated on a twelve consecutive month rolling basis shall not exceed any of the following: NO_x (as NO_2) - 306,920 lb/year; VOC - 26,712 lb/year; and PM_{10} - 164,800 lb/year. [District Rule 2201]

- The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rule 2201]

- Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O_2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NO_x concentration ppmvd @ 15% O_2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH_3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102]

- 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. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Quarterly emissions shall be calculated for each calendar quarter in a year. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

- Source testing to demonstrate compliance with the NO_x, CO, and VOC short-term emission limits (lb/hr and ppmv @ 15% O_2) shall be conducted within 60 days of initial operation of CTG and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

- Source testing to demonstrate compliance with PM_{10} short-term emission limit (lb/hr) shall be conducted within 60 days of initial operation, and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

- Source testing of startup NO_x, CO, VOC, and PM_{10} mass emission rates shall be conducted for one of the gas turbine engines (N-4597-1 or N-4597-2) upon initial operation and at least once every seven years thereafter by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm. CEM relative accuracy shall be determined during startup source testing in accordance with District-approved protocol. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of this unit and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

- The District must be notified 30 days prior to any source testing, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source testing shall be submitted to the District within 60 days of testing. [District Rule 1081]

- Permittee shall maintain hourly records of NO_x and CO emission concentrations (ppmv @ 15% O_2), and hourly, daily, and annual records of NO_x and CO emissions. Compliance with the hourly, daily, and annual VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]

- Permittee shall maintain records of SO_x emissions rates in lb/hr and lb/day. SO_x emission rates shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

- Permittee shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703]

- Permittee shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 and 4703]

- 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 1080]

- Permittee 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 1100]

- The District shall be notified in writing within ten days 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 1100]

- Permittee 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 1080]

- The permittee shall submit a written report for each calendar quarter to the APCO. The report shall be received by the District within 30 days of the end of the quarter and shall include: time intervals, data and magnitude of excess emissions; nature and cause of excess emissions (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during which a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

- Source testing to demonstrate compliance with the NO_x, CO, VOC, PM_{10}, NH_3 and fuel gas sulfur content requirements of this permit shall be conducted within 60 days of initial operation. Source testing for NO_x, CO, VOC, PM_{10} and NH_3 shall be conducted at least once every twelve months thereafter. [District Rule 2201 and 4001]

- Source testing to determine the percent efficiency of the turbine shall be conducted annually. [District Rule 4703]

- Testing to demonstrate compliance with the fuel sulfur content limit of this permit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit of this permit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [District Rule 2201]

- The results of each source test shall be received by the District no later than 60 days after the source test date. [District Rule 1081]

- Source testing shall be witnessed or authorized by District personnel. [District Rule 1081]

- Source testing for NO_x shall be conducted utilizing EPA method 7E or EPA method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 4001 and 4703]

- Source testing for CO shall be conducted utilizing EPA method 10 or EPA method 10 B. [District Rule 4703]

- Source testing for VOC shall be conducted utilizing EPA method 18 or EPA method 25. [District Rule 2201]

- Source testing to measure concentrations of PM_{10} shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. [District Rule 2201]

- Source testing for stack O_2 content shall be conducted utilizing EPA method 3, EPA method 3A or EPA method 20. [District Rule 4703]

- Testing for fuel sulfur content shall be conducted utilizing ASTM method D 3246. [District Rule 4001]

- Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 2201 and 4703]

- The permittee shall maintain a daily record that includes the actual turbine start-up and stop times (local time), length and reason for reduced load periods, total hours of operation, and the quantity of fuel used. [District Rule 4703]

- The permittee shall maintain records of the cumulative annual facility-wide NO_x, VOC, and PM_{10} emissions. The records shall be updated daily. [District Rule 2201]

- The permittee shall maintain hourly records of NO_x, CO and ammonia concentrations (ppmv @ 15% O_2). [District Rule]

- The permittee shall submit to the District a plan for monitoring and recording the cumulative annual facility-wide CO and SO_x emissions. The plan shall be received by the District at least 90 days prior to the planned start-up date and shall be approved by the District prior to the implementation of the plan. [District Rule 2201]

- The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. 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 4703]

- All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201]

- Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

- Permittee shall submit an application to comply with Rule 2540 (Acid Rain Program) at least 24 months prior to the date that the unit commences operation. [District Rule 2540]

- At least 30 days prior to commencement of construction, the permittee shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

- Upon implementation of this Authority to Construct permit, emission offsets shall be provided for NO_x, VOC, and PM_{10}. The offsets shall be provided at the offset ratio specified in District Rule 2201 (New and Modified Stationary Source Review). [District Rule 2201]

- Offsets shall be provided in the amount that will mitigate the increase in NO_x emissions of 71,730 pounds per calendar quarter, the increase in VOC emissions of 1,678 pounds per calendar quarter, and the increase in PM_{10} emissions of 33,900 pounds per calendar quarter. [District Rule 2201]

- SO_x reductions may be utilized to offset PM_{10} emission increases. The combined distance/interpollutant offset ratio shall be 2.2 pounds of SO_x per 1.0 pound of PM_{10} if the reductions occurred within 15 miles of the proposed facility. The combined distance/interpollutant offset ratio shall be 2.5 pounds of SO_x per 1.0 pound of PM_{10} if the reductions occurred 15 miles or more from the proposed facility. [District Rule 2201]

<u>EQUIPMENT DESCRIPTION, UNIT N-4597-2-0</u>:
84.4 MW NOMINALLY RATED SIMPLE-CYCLE PEAK-DEMAND POWER GENERATING SYSTEM #2 CONSISTING OF A GENERAL ELECTRIC MODEL PG 7121 EA NATURAL GAS-FIRED COMBUSTION TURBINE GENERATOR SERVED BY AN INLET AIR FILTRATION AND COOLING SYSTEM, DRY LOW-NOX COMBUSTORS, A SCR SYSTEM WITH AMMONIA INJECTION, AND AN OXIDATION CATALYST

- The permittee shall not begin actual onsite construction of the equipment authorized by this Authority to Construct until the lead agency satisfies the requirements of the California Environmental Quality Act (CEQA). [California Environmental Quality Act]

- The permittee shall notify the District of the date of initiation of construction no later than 30 days after such date, the date of anticipated startup not more than 60 days nor less than 30 days prior to such date, and the date of actual startup within 15 days after such date. [District Rule 4001]

- {118} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

- {14} Particulate matter emissions shall not exceed 0.1 grains/dscf in concentration. [District Rule 4201]

- {15} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is as dark as, or darker than, Ringelmann 1 or 20% opacity. [District Rule 4101]

- Permittee shall submit continuous emission monitor design, installation, and operational details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- CTG exhaust shall be equipped with continuously recording emissions monitor(s) dedicated to this unit for NO_x, CO, and O_2. Continuous emissions monitor(s) shall meet the requirements of 40 CFR part 60, Appendices B and F, and 40 CFR part 75, and District-approved protocol, and shall be capable of monitoring emissions during normal operating conditions and during startups and shutdowns, provided the CEM(s) pass the relative accuracy requirement for startups and shutdowns specified herein. If relative accuracy of CEM(s) cannot be demonstrated during startup conditions, CEM 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 2201, 4001, and 4703]

- The gas turbine engine shall be equipped with a continuous monitoring system to measure and record hours of operation and fuel consumption. [District Rules 2201, 4001, and 4703]

- The CEM for NO_x and O_2 shall meet the applicable performance specification requirements in 40 CFR, Part 51, Appendix P and Part 60, appendix B, or shall meet equivalent specifications established by mutual agreement of the District, the ARB and the Environmental Protection Agency. [District Rule 1080]

- Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing was performed in accordance with EPA guidelines. The District shall be notified prior to completion of the audits. Audit reports shall be submitted to the District along with quarterly compliance reports. [District Rule 1080]

- Combustion turbine generator (CTG) and electrical generator lube oil vents shall be equipped with mist eliminators to maintain visible emissions from lube oil vents no greater than 5% opacity, except for three minutes in any hour. [District Rule 2201]

- All equipment shall be maintained in proper operating condition and shall be operated in a manner to minimize emissions of air contaminants into the atmosphere. [District Rule 2201]

- The permittee shall monitor and record the NO_x emission rate, the CO emissions rate, the ammonia injection rate, the exhaust temperature, the exhaust oxygen content, and the exhaust flow rate. [District Rule 4703 and 4001]

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- The exhaust stack shall be equipped with permanent provisions for stack gas sample collection. 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. [District Rule 1081]

- A selective catalytic reduction (SCR) system and oxidation catalyst shall serve the gas turbine engine. Exhaust ducting shall be equipped with a fresh air inlet and blower to be used to lower the exhaust temperature prior to inlet of the SCR system catalyst. Permittee shall submit SCR and oxidation catalyst design details to the District at least 30 days prior to commencement of construction. [District Rule 2201]

- This unit shall exclusively burn only natural gas with a sulfur content no greater than 0.25 grains of sulfur compounds (as S) per 100 dry scf of natural gas. [District Rule 2201]

- During startup or shutdown of any gas turbine engine, combined emissions from the two gas turbine engines (N-4597-1 and N-4597-2) shall not exceed the following: NO_x - 26 lb and CO - 42 lb in any one hour. [California Environmental Quality Act]

- Startup is defined as the period beginning with turbine initial firing until the unit meets the lb/hr and ppmvd emission limits. Shutdown is defined as the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup of the CTG shall not exceed a time period of 20 minutes each per occurrence. Shutdown of the CTG shall not exceed a time period of 30 minutes each per occurrence. Startup and shutdown events shall not exceed 250 occurrences per calendar year and once per day. [District Rule 2201]

- Operation of this unit shall not exceed 8,000 hours per calendar year. [District Rule 2201]

- Emissions from this unit, except during startup and shutdown events, shall not exceed any of the following: NO_x (as NO_2) - 25.25 lb/hr and 5.0 ppmvd @ 15% O_2; VOC - 2.33 lb/hr and 2.0 ppmvd @ 15% O_2; CO - 20.09 lb/hr and 6.0 ppmvd @ 15% O_2; PM_{10} - 10.3 lb/hr; and SO_x (as SO_2) - 0.70 lb/hr. All emission concentration limits are three-hour rolling averages. [District Rules 2201, 4001, and 4703]

- Emissions from this unit shall not exceed any of the following: NO_x (as NO_2) - 451.6 lb/day; VOC - 39.4 lb/day; CO - 219.0 lb/day; PM_{10} - 247.2 lb/day; and SO_x (as SO_2) - 16.8 lb/day. [District Rule 2201]

- Combined quarterly emissions from N-4597-1 and N-4597-2 shall be calculated for each calendar quarter and shall not exceed any of the following: NO_x (as NO_2) - Q1: 76,704 lb, Q2: 76,704 lb, Q3: 76,756 lb, and Q4: 76,756 lb; VOC - Q1: 6,676 lb, Q2: 6,676 lb, Q3: 6,680 lb, and Q4: 6,680 lb; and PM_{10} - Q1: 41,200 lb, Q2: 41,200 lb, Q3: 41,200 lb, and Q4: 41,200 lb. [District Rule 2201]

- Combined annual emissions from N-4597-1 and N-4597-2 calculated on a twelve consecutive month rolling basis shall not exceed any of the following: NO_x (as NO_2) - 306,920 lb/year; VOC - 26,712 lb/year; and PM_{10} - 164,800 lb/year. [District Rule 2201]

- The ammonia (NH_3) emissions shall not exceed 10 ppmvd @ 15% O_2 over a 24 hour rolling average. [District Rule 2201]

- Compliance with ammonia slip limit shall be demonstrated utilizing the following calculation procedure: ammonia slip ppmvd @ 15% O_2 = ((a - (b x c/1,000,000)) x (1,000,000 / b) x d, where a = ammonia injection rate (lb/hr) / (17 lb/lb mol), b = dry exhaust flow rate (lb/hr) / (29 lb/lb mol), c = change in measured NO_x concentration ppmvd @ 15% O_2 across the catalyst and d = correction factor. The correction factor shall be derived annually during compliance testing by comparing the measured and calculated ammonia slip. Alternatively, the permittee may utilize a continuous in-stack ammonia monitor, acceptable to the District to monitor compliance. At least 60 days prior to using a NH_3 CEM, the permittee shall submit a monitoring plan for District review and approval. [District Rule 4102]

- 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. [District Rule 2201]

- Daily emissions will be compiled for a twenty-four hour period starting and ending at twelve-midnight. Quarterly emissions shall be calculated for each calendar quarter in a year. Each calendar month in a twelve consecutive month rolling emissions total will commence at the beginning of the first day of the month. The twelve consecutive month rolling emissions total to determine compliance with annual emission limits will be compiled from the twelve most recent calendar months. [District Rule 2201]

- Source testing to demonstrate compliance with the NO_x, CO, and VOC short-term emission limits (lb/hr and ppmv @ 15% O_2) shall be conducted within 60 days of initial operation of CTG and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

- Source testing to demonstrate compliance with PM_{10} short-term emission limit (lb/hr) shall be conducted within 60 days of initial operation, and annually thereafter by District witnessed sampling of exhaust gas by qualified independent source testers. [District Rule 1081]

- Source testing of startup NO_x, CO, VOC, and PM_{10} mass emission rates shall be conducted for one of the gas turbine engines (N-4597-1 or N-4597-2) upon initial operation and at least once every seven years thereafter by District witnessed in-situ sampling of exhaust gases by a qualified independent source test firm. CEM relative accuracy shall be determined during startup source testing in accordance with District-approved protocol. [District Rule 1081]

- Compliance with natural gas sulfur content limit shall be demonstrated within 60 days of operation of this unit and periodically as required by 40 CFR 60 Subpart GG and 40 CFR 75. [District Rules 1081, 2540, and 4001]

- The District must be notified 30 days prior to any source testing, and a source test plan must be submitted for approval 15 days prior to testing. Official test results and field data collected by source testing shall be submitted to the District within 60 days of testing. [District Rule 1081]

- Permittee shall maintain hourly records of NO_x and CO emission concentrations (ppmv @ 15% O_2), and hourly, daily, and annual records of NO_x and CO emissions. Compliance with the hourly, daily, and annual VOC emission limits shall be demonstrated by the CO CEM data and the VOC/CO relationship determined by annual CO and VOC source tests. [District Rule 2201]

- Permittee shall maintain records of SO_x emissions rates in lb/hr and lb/day. SO_x emission rates shall be based on fuel use records, natural gas sulfur content, and mass balance calculations. [District Rule 2201]

- Permittee shall maintain the following records for the CTG: occurrence, duration, and type of any startup, shutdown, or malfunction; emission measurements; total daily and annual hours of operation; and hourly quantity of fuel used. [District Rules 2201 and 4703]

- Permittee shall maintain the following records for the continuous emissions monitoring system (CEMS): performance testing, evaluations, calibrations, checks, maintenance, adjustments, and any period of non-operation of any continuous emissions monitor. [District Rules 2201 and 4703]

- 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 1080]

- Permittee 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 1100]

- The District shall be notified in writing within ten days 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 1100]

- Permittee 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 1080]

- The permittee shall submit a written report for each calendar quarter to the APCO. The report shall be received by the District within 30 days of the end of the quarter and shall include: time intervals, data and magnitude of excess emissions; nature and cause of excess emissions (averaging period used for data reporting shall correspond to the averaging period for each respective emission standard); corrective actions taken and preventive measures adopted; applicable time and date of each period during which a CEM was inoperative (except for zero and span checks) and the nature of system repairs and adjustments; and a negative declaration when no excess emissions occurred. [District Rule 1080]

- Source testing to demonstrate compliance with the NO_x, CO, VOC, PM_{10}, NH_3 and fuel gas sulfur content requirements of this permit shall be conducted within 60 days of initial operation. Source testing for NO_x, CO, VOC, PM_{10} and NH_3 shall be conducted at least once every twelve months thereafter. [District Rule 2201 and 4001]

- Source testing to determine the percent efficiency of the turbine shall be conducted annually. [District Rule 4703]

- Testing to demonstrate compliance with the fuel sulfur content limit of this permit shall be conducted weekly. Once eight consecutive weekly tests show compliance, the fuel sulfur content testing frequency may be reduced to once every calendar quarter. If a quarterly test shows a violation of the sulfur content limit of this permit then weekly testing shall resume and continue until eight consecutive tests show compliance. Once compliance is shown on eight consecutive weekly tests then testing may return to quarterly. [District Rule 2201]

- The results of each source test shall be received by the District no later than 60 days after the source test date. [District Rule 1081]

- Source testing shall be witnessed or authorized by District personnel. [District Rule 1081]

- Source testing for NO_x shall be conducted utilizing EPA method 7E or EPA method 20. The test results shall be corrected to ISO standard conditions as defined in 40 CFR Part 60 Subpart GG Section 60.335. [District Rules 4001 and 4703]

- Source testing for CO shall be conducted utilizing EPA method 10 or EPA method 10 B. [District Rule 4703]

- Source testing for VOC shall be conducted utilizing EPA method 18 or EPA method 25. [District Rule 2201]

- Source testing to measure concentrations of PM_{10} shall be conducted using EPA methods 201 and 202, or EPA methods 201A and 202, or CARB method 501 in conjunction with CARB method 5. [District Rule 2201]

- Source testing for stack O_2 content shall be conducted utilizing EPA method 3, EPA method 3A or EPA method 20. [District Rule 4703]

- Testing for fuel sulfur content shall be conducted utilizing ASTM method D 3246. [District Rule 4001]

- Source testing to determine the percent efficiency of the turbine shall be conducted utilizing the procedures in District Rule 4703 (Stationary Gas Turbines). [District Rule 4703]

- The permittee shall maintain the following records: the date, time and duration of any malfunction of the continuous monitoring equipment; dates of performance testing; dates of evaluations, calibrations, checks, and adjustments of the continuous monitoring equipment; date and time period which a continuous monitoring system or monitoring device was inoperative. [District Rules 2201 and 4703]

- The permittee shall maintain a daily record that includes the actual turbine start-up and stop times (local time), length and reason for reduced load periods, total hours of operation, and the quantity of fuel used. [District Rule 4703]

- The permittee shall maintain records of the cumulative annual facility-wide NO_x, VOC, and PM_{10} emissions. The records shall be updated daily. [District Rule 2201]

- The permittee shall maintain hourly records of NO_x, CO and ammonia concentrations (ppmv @ 15% O_2). [District Rule]

- The permittee shall submit to the District a plan for monitoring and recording the cumulative annual facility-wide CO and SO_x emissions. The plan shall be received by the District at least 90 days prior to the planned start-up date and shall be approved by the District prior to the implementation of the plan. [District Rule 2201]

- The permittee shall submit to the District information correlating the NO_x control system operating parameters to the associated measured NO_x output. 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 4703]

- All records required to be maintained by this permit shall be maintained for a period of two years and shall be made readily available for District inspection upon request. [District Rule 2201]

- Permittee shall submit an application to comply with Rule 2520 - Federally Mandated Operating Permits prior to the implementation of this Authority to Construct to a Permit to Operate. [District Rule 2520]

- Permittee shall submit an application to comply with Rule 2540 (Acid Rain Program) at least 24 months prior to the date that the unit commences operation. [District Rule 2540]

- At least 30 days prior to commencement of construction, the permittee shall provide the District with written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into. [District Rule 2201]

- Upon implementation of this Authority to Construct permit, emission offsets shall be provided for NO_x, VOC, and PM_{10}. The offsets shall be provided at the offset ratio specified in District Rule 2201 (New and Modified Stationary Source Review). [District Rule 2201]

- Offsets shall be provided in the amount that will mitigate the increase in NO_x emissions of 71,730 pounds per calendar quarter, the increase in VOC emissions of 1,678 pounds per calendar quarter, and the increase in PM_{10} emissions of 33,900 pounds per calendar quarter. [District Rule 2201]

- SO_x reductions may be utilized to offset PM_{10} emission increases. The combined distance/interpollutant offset ratio shall be 2.2 pounds of SO_x per 1.0 pound of PM_{10} if the reductions occurred within 15 miles of the proposed facility. The combined distance/interpollutant offset ratio shall be 2.5 pounds of SO_x per 1.0 pound of PM_{10} if the reductions occurred 15 miles or more from the proposed facility. [District Rule 2201]

EQUIPMENT DESCRIPTION, UNIT N-4597-3-0:
382 HP CATERPILLAR MODEL ATAAC DIESEL-FIRED EMERGENCY IC ENGINE POWERING A 250 KW ELECTRICAL GENERATOR

- {1594} No air contaminant shall be released into the atmosphere which causes a public nuisance. [District Rule 4102]

- {1601} No air contaminant shall be discharged into the atmosphere for a period or periods aggregating more than three minutes in any one hour which is dark or darker than Ringelmann 1 or equivalent to 20% opacity. [District Rule 4101]

- {1599} Particulate matter emissions shall not Exceed 0.1 grains/dscf in concentration. [District Rule 4201]

- {1595} The engine shall be equipped with a positive crankcase ventilation (PCV) system or a crankcase emissions control device of at least 90% control efficiency. [District Rule 2201]

- This engine shall be operated only for maintenance, testing, and required regulatory purposes, and during emergency situations. Operation of the engine for maintenance, testing, and required regulatory purposes shall not exceed 200 hours per year. [District Rules 2201 and 4701]

- The exhaust stack(s) shall not be fitted with a rain cap or any similar device that would impede vertical exhaust flow. [District Rule 4102]

- NO_x emissions shall not exceed 5.09 g/hp-hr. [District Rule 2201]

- VOC emissions shall not exceed 0.14 g/hp-hr. [District Rule 2201]

- CO emissions shall not exceed 1.13 g/hp-hr. [District Rule 2201]

- PM_{10} emissions shall not exceed 0.13 g/bhp-hr based on U.S EPA certification using ISO 8178 test procedure. [District Rules 2201 and 4102]

- Only CARB-certified diesel fuel containing not more than 0.05% sulfur by weight shall be used. [District Rules 2201 and 4102]

- The permittee shall maintain records of hours of emergency and non-emergency operation. Records shall include the date, the number of hours of operation, the purpose of the operation (e.g., load testing, weekly testing, rolling blackout, general area power outage, etc.), and the sulfur content of the diesel fuel used. Such records shall be made available for District inspection upon request for a period of two years. [District Rules 2201 and 4701]

ATTACHMENT B

CTG Emissions Data

Owner CED
Plant GWF Tracy
Project No. 68389
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No

Computed By [illegible]
Date 12:00:00 AM
Verified By ______
Date ______

28-Jul-01			
CED			
GWF Tracy			
68389			
Simple Cycle Plant Emissions Estimate, Revision 3			
[illegible]	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
[illegible]	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Cust Gas	Cust Gas	Cust Gas
[illegible]	100%	80%	60%
CTG Inlet Air Conditioning in Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
[illegible]	59	59	59
[illegible]	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Ambient Temperature, F	59.0	59.0	59.0
Ambient Relative Humidity, %	60.0	60.0	60.0
Atmospheric Pressure, psia	14.604	14.604	14.604
CTG Inlet Air Conditioning Effectiveness, %	85	85	85
CTG Compressor Inlet Dry Bulb Temperature, F	52.6	52.6	52.6
CTG Compr. Inlet Relative Humidity, %	92.9	92.9	92.9
Evaporative Cooler Evaporation Rate, lb/h	4561.3	3741.4	3172.9
Inlet Loss, in H2O	4.5	4.5	4.5
Exhaust Loss, in H2O	10.0	10.0	10.0
CTG Performance Reference	GTPE	GTPE	GTPE
CTG Load Level (percent of Base Load)	100%	80%	60%
Gross CTG Output, kW	85,620	68,012	51,014
Gross CTG Heat Rate, Btu/kWh (LHV)	10,500	11,020	12,610
Gross CTG Heat Rate, Btu/kWh (HHV)	11,651	12,228	13,992
CTG Heat Input, MBtu/h (LHV)	862.7	749.5	643.3
CTG Heat Input, MBtu/h (HHV)	990.5	831.7	713.8
CTG Water Injection Flow, lb/h	0	0	0
CTG Steam Injection Flow, lb/h	0	0	0
Injection Fluid/Fuel Ratio	0.0	0.0	0.0
CTG Exhaust Flow, lb/h	2,321,106	1,962,103	1,606,093
CTG Exhaust Temperature, F	998	1,032	1,064
Total CTG Fuel Flow, lb/h	43,[illegible]	36,[illegible]	31,[illegible]
CTG Fuel Temperature, F	90	90	90
CTG Fuel LHV, Btu/lb	20,728	20,728	20,728
CTG Fuel HHV, Btu/lb	23,000	23,000	23,000
HHV/LHV Ratio	1.1096	1.1096	1.1096
CTG Fuel Composition (Ultimate Analysis by Weight)			
Ar	0.00%	0.00%	0.00%
C	73.19%	73.19%	73.19%
H2	23.97%	23.97%	23.97%
N2	1.55%	1.55%	1.55%
O2	1.29%	1.29%	1.29%
S	0.00064%	0.00064%	0.00064%
Total	100.00%	100.00%	100.00%
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20

Owner CED
Plant GWF Tracy
Project No. 69368
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No.

Computed By [illegible]
Date 12:00:00 AM
Verified By
Date

[illegible]			
CED			
GWF Tracy			
69368			
Simple Cycle Plant Emissions Estimate, Revision 3			
Case Number	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
[illegible]	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Cust Gas	Cust Gas	Cust Gas
CTG Load	100%	80%	60%
CTG Inlet Air Conditioning In Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
Ambient Temperature, F	59	59	59
HRSG [illegible]	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Combustion Turbine Exhaust Emissions			
CTG Exhaust Analysis (Volume Basis - Wet)			
Ar	0.94%	0.94%	0.94%
CO_2	3.12%	3.19%	3.23%
H_2O	7.30%	7.43%	7.50%
N_2	74.71%	74.85%	74.62%
O_2	13.94%	13.78%	13.71%
SO_2	0.00001%	0.00001%	0.00001%
Total	100.0%	100.0%	100.0%
NOx, ppmvd @ 15% O_2	9.00	9.00	9.00
NOx, ppmvd	8.96	9.16	9.27
NOx, ppmvw (wet - uncorrected exhaust gas)	8.29	8.48	8.58
NOx, lb/h as NO_2	33.1	27.9	24.1
NOx, lb/MBtu (LHV)	0.0373	0.0373	0.0375
NOx, lb/MBtu (HHV)	0.0334	0.0336	0.0338
CO, ppmvd @ 15% O_2	25.15	24.55	24.36
CO, ppmvd	25.00	25.00	25.00
CO, ppmvw (wet - uncorrected exhaust gas)	23.13	23.14	23.12
CO, lb/h	54.6	46.7	37.4
CO, lb/MBtu (LHV)	0.0611	0.0562	0.0589
CO, lb/MBtu (HHV)	0.0551	0.0536	0.0531
NOTE: SO2 estimate does not include the effects of SO2 oxidation			
SO2, ppmvd @ 15% O2 (with no SO2 oxidation)	0.11	0.11	0.11
SO2, ppmvd (with no SO2 oxidation)	0.11	0.11	0.11
SO2, ppmvw (with no SO2 oxidation)(wet - uncorrected exhaust gas)	0.10	0.11	0.11
SO2, lb/h (with no SO2 oxidation)	0.55	0.48	0.40
SO2, lb/MBtu (LHV) (with no SO2 oxidation)	0.0006	0.0006	0.0006
SO2, lb/MBtu (HHV) (with no SO2 oxidation)	0.0006	0.0006	0.0005

Owner CED
Plant GWF Tracy
Project No. 89389
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No

Computed By ?
Date 12:00:00 AM
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Date

20-Jul-01			
CED			
GWF Tracy			
89389			
Simple Cycle Plant Emissions Estimate, Revision 3			
Case Number	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
Diluent	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Cust Gas	Cust Gas	Cust Gas
CTG Load	100%	60%	60%
CTG Inlet Air Conditioning in Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
Ambient Temperature, F	59	59	59
HRSG Firing	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Combustion Turbine Exhaust Emissions - continued			
UHC, ppmvd @ 15% O2	7.60	7.43	7.34
UHC, ppmvd	7.56	7.56	7.57
UHC, ppmvw (wet - uncorrected exhaust gas)	7.00	7.00	7.00
UHC, lb/h as CH4	9.4	7.8	6.6
UHC, lb/MBtu as CH4 (LHV)	0.0106	0.0103	0.0102
UHC, lb/MBtu as CH4 (HHV)	0.0095	0.0093	0.0092
VOC percentage of UHC	20%	20%	20%
VOC, ppmvd @ 15% O2	1.5	1.5	1.4
VOC, ppmvd	1.51	1.51	1.51
VOC, ppmvw (wet - uncorrected exhaust flow)	1.40	1.40	1.40
VOC, lb/h as CH4	1.9	1.5	1.3
VOC, lb/MBtu as CH4 (LHV)	0.0021	0.0021	0.0020
VOC, lb/MBtu as CH4 (HHV)	0.0019	0.0019	0.0019
Particulates, lb/h (front half catch only)	5.0	5.0	5.0
Particulates, lb/h (front and back half catch)	10.0	10.0	10.0
Particulates, lb/MBtu (LHV) (front half catch only)	0.0056	0.0067	0.0076
Particulates, lb/MBtu (HHV) (front half catch only)	0.0050	0.0060	0.0070
PM10, lb/h (front half catch only)	5.0	5.0	5.0
PM10, lb/h (front and back half catch)	10.0	10.0	10.0
PM10, lb/MBtu (LHV) (front and back half catch)	0.0112	0.0133	0.0155
PM10, lb/MBtu (HHV) (front and back half catch)	0.0101	0.0120	0.0140
CTG Wet (Total) Exhaust Gas Analysis			
Molecular Wt, lb/mol	28.45	28.45	28.44
Gas Constant, ft-lbf/lbm-R	54.300	54.370	54.330
Specific Volume, ft3/lb	38.88	37.60	38.91
Exhaust Gas Flow, acfm	1,461,783	1,229,622	1,079,885
Specific Volume, scf/lb	13.33	13.34	13.34
Exhaust Gas Flow, scfm	631,294	436,254	370,160

Owner CED
Plant GWF Tracy
Project No 89389
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No.

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Date 12:00:00 AM
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Date ______

28-Jul-01			
CED			
GWF Tracy			
89389			
Simple Cycle Plant Emissions Estimate, Revision 3			
Case Number	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
Source	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Cust Gas	Cust Gas	Cust Gas
CTG Load	100%	80%	60%
CTG Inlet Air Conditioning in Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
Ambient Temperature	59	59	59
[illegible]	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Stack Emissions			
NOTE: Exhaust Analysis does not include the effects of post combustion control			
Stack Exhaust Analysis (Volume Basis - Wet)			
Ar	0.94%	0.94%	0.94%
CO2	2.80%	2.55%	2.44%
H2O	8.26%	6.15%	5.93%
N2	75.13%	75.17%	75.20%
O2	15.08%	15.18%	15.43%
SO2	0.00001%	0.00001%	0.00001%
Total	100.0%	100.0%	100.0%
Stack Emissions			
NOx, ppmvd @15% O2 w/o SCR, does not account for added margin	9.00	9.00	9.00
NOx, ppmvd w/o SCR	7.36	7.23	6.89
NOx, ppmvw w/o SCR	[illegible]	[illegible]	6.48
NOx, lb/h as NO2 w/o SCR (includes correction added)	25.37	[illegible]	24.19
NOx, lb/MBtu (LHV) as NO2 w/o SCR	0.0370	0.0373	0.0375
NOx, lb/MBtu (HHV) as NO2 w/o SCR	0.0334	0.0336	0.0338
NOx, ppmvd @15% O2 w/ SCR	5.00	5.00	5.00
NOx, ppmvd w SCR	4.09	4.02	[illegible]
NOx, ppmvw w SCR	3.84	3.77	[illegible]
NOx, lb/h as NO2 w SCR (includes NOx margin applied to CTG)	18.37	15.51	13.39
NOx, lb/MBtu (LHV) as NO2 w SCR	0.0206	0.0207	0.0208
NOx, lb/MBtu (HHV) as NO2 w SCR	0.0185	0.0187	0.0188
SCR NH3 slip, ppmvd @15% O2	10.00	10.00	10.00
SCR NH3 slip, lb/h	13.19	11.07	8.50
CO, ppmvd @ 15% O2 w/o Catalyst	25.15	24.55	24.26
CO, ppmvd w/o Catalyst	20.58	19.75	18.97
CO, ppmvw w/o Catalyst	19.79	18.51	17.47
CO, lb/h w/o Catalyst (includes CO correction as applied to CTG and margin)	54.55	44.71	37.92
CO, lb/MBtu (LHV) w/o SCR	0.0611	0.0597	0.0589
CO, lb/MBtu (HHV) w/o SCR	0.0551	0.0538	0.0531
CO Reduction % w/ Catalyst	86%	86%	86%
CO, ppmvd @ 15% O2 w/ Catalyst	3.52	3.44	3.40
CO, ppmvd w/ Catalyst	2.88	2.76	2.60
CO, ppmvw w/ Catalyst	2.70	2.59	2.45
CO, lb/h w/ Catalyst (includes CO margin applied to CTG)	7.64	6.26	5.31
CO, lb/MBtu (LHV) w SCR	0.0086	0.0084	0.0083
CO, lb/MBtu (HHV) w SCR	0.0077	0.0075	0.0074
SO2, ppmvd@15% O2 w/o scrubber (with no SO2 oxidation)	0.111	0.111	0.111
SO2, ppmvd w/o scrubber (with no SO2 oxidation)	0.09	0.09	0.09
SO2, ppmvw w/o scrubber (with no SO2 oxidation)	0.09	0.08	0.08
SO2, lb/h w/o scrubber (with no SO2 oxidation)	0.55	0.46	0.40
SO2, lb/MBtu (LHV) w/o scrubber	0.0006	0.0006	0.0006
SO2, lb/MBtu (HHV) w/o scrubber	0.0006	0.0006	0.0006

Owner CED
Plant GWF Tracy
Project No. 89389
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No

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Date 12:00:00 AM
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20-Jul-01
CED
GWF Tracy
89389
Simple Cycle Plant Emissions Estimate, Revision 3

Case Number	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
Driver	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Gas	Gas	Gas
CTG Load	100%	80%	60%
CTG Inlet Air Conditioning In Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
Ambient Temperature	59	59	59
HRSG Firing	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Stack Emissions - continued			
NOTE: UHC emissions do NOT include the effect of any oxidation in the CO catalyst.			
UHC, ppmvd @ 15% O2	7.60	7.43	7.34
UHC, ppmvd	6.22	5.57	5.62
UHC, ppmvw	5.83	5.60	5.29
UHC, lb/h as CH4	8.44	7.75	6.27
UHC, lb/MBtu (LHV)	0.0106	0.0103	0.0102
UHC, lb/MBtu (HHV)	0.0095	0.0093	0.0092
VOC, ppmvd @ 15% O2 w/o Catalyst	1.52	1.49	1.47
VOC, ppmvd w/o Catalyst	1.24	1.19	1.12
VOC, ppmvw w/o Catalyst	1.17	[illegible]	1.06
VOC, lb/h as CH4 w/o Catalyst (includes correction adder)	1.99	[illegible]	1.31
VOC, lb/MBtu (LHV) w/o CO catalyst	0.0021	[illegible]	0.0020
VOC, lb/MBtu (HHV) w/o CO catalyst	0.0019	0.0019	0.0018
VOC Reduction % w/ Catalyst	16%	16%	16%
VOC, ppmvd @ 15% O2 w/ Catalyst	1.28	1.25	1.23
VOC, ppmvd w/ Catalyst	1.04	1.00	0.94
VOC, ppmvw w/ Catalyst	0.98	0.94	0.89
VOC, lb/h as CH4 w/ Catalyst (includes VOC correction as applied to CTG)	1.59	1.30	1.10
VOC, lb/MBtu (LHV) w CO catalyst	0.0018	[illegible]	0.0017
VOC, lb/MBtu (HHV) w CO catalyst	0.0016	0.0016	0.0015
Particulate without the effect of SO2 oxidation and SCR catalysts			
Particulates, lb/h (front half catch only)	5.0	5.0	5.0
Particulates, lb/MBtu (front half catch only)	0.0056	0.0067	0.0078
Particulates, lb/h (front and back half catch)	10.0	10.0	10.0
Particulates, lb/MBtu (front and back half catch)	0.0112	0.0133	0.0155
PM10, lb/h (front half catch only)	5.0	5.0	5.0
PM10, lb/MBtu (front half catch only)	0.0056	0.0067	0.0078
PM10, lb/h (front and back half catch)	10.0	10.0	10.0
PM10, lb/MBtu (front and back half catch)	0.0112	0.0133	0.0155
Particulates including the effect of SO2 oxidation and SCR catalysts (includes (NH4)2-(SO4))			
Particulates, lb/h (front half catch only)	5.3	5.3	5.3
Particulates, lb/MBtu(front half catch only)	0.0060	0.0071	0.0082
Particulates, lb/h (front and back half catch)	10.3	10.3	10.3
Particulates, lb/MBtu(front and back half catch)	0.0116	0.0137	0.0159
PM10, lb/h (front half catch only)	5.3	5.3	5.3
PM10, lb/MBtu(front half catch only)	0.0060	0.0071	0.0082
PM10, lb/h (front and back half catch)	10.3	10.3	10.3
PM10, lb/MBtu(front and back half catch)	0.0116	0.0137	0.0159
NOTE: SO2 to SO3 conversion rate (assumed), wt%	30.0%	30.0%	30.0%
Remaining SO2 in Exhaust Gas, lb/h	0.39	0.33	0.29
Amount of SO2 converted to SO3, lb/h	0.17	0.14	0.12
Maximum Exhaust Gas ammonium sulfate ((NH4)2-(SO4)) (assuming 100% conversion from SO3), lb/h	0.34	0.29	0.25
Maximum H2SO4 (assuming 100% conversion from SO3 to H2(SO4)), lb/h	0.25	0.21	0.18

Owner CED
Plant CWF Tracy
Project No. 69389
Title Simple Cycle Plant Emissions Estimate, Revision 3

Unit
File No

Computed By 0
Date 12:00:00 AM
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Date ________

20 Jul 01
CED
CWF Tracy
69389
Simple Cycle Plant Emissions Estimate, Revision 3

[illegible]	7	8	9
CTG Model	GE 7EA	GE 7EA	GE 7EA
[illegible]	DN 9/42	DN 9/42	DN 9/42
CTG Fuel Type	Cust Gas	Cust Gas	Cust Gas
CTG Load	100%	80%	80%
CTG Inlet Air Conditioning in Operation?	Evap. Cooler	Evap. Cooler	Evap. Cooler
Ambient Temperature, F	59	59	59
[illegible]	Unfired	Unfired	Unfired
Fuel Sulfur Content (grains/100 standard cubic feet)	0.20	0.20	0.20
Stack			
Stack Exit Temperature, F	850	850	850
Stack Diameter, ft (estimated)	17.0	17.0	17.0
Stack Flow, lb/h	2,879,241	2,480,359	2,311,650
Stack Flow, scfm	638,232	549,302	489,867
Stack Flow, acfm	1,610,089	1,383,134	1,249,080
Stack Exit Velocity, ft/s	119.0	102.3	91.0
Post Combustion Emissions Control			
CO Catalyst			
CO removed in CO Catalyst, %	86%	82%	85%
CO removed in CO Catalyst, lb/h (includes CO correction as applied in CTG)	48.92	38.45	32.51
Selective Catalytic Reduction (SCR)			
NOx Removed, lb/h as NO2	14.70	12.41	10.71
NOx Removed, percent	44.4%	44.4%	44.4%
NH3 Slip, lb/h	13.3	11.1	9.5
Stack Exhaust Gas Analysis (Wet)			
Molecular Wt, lb/mol	28.5	28.5	28.5
Specific Volume, ft^3/lb	33.7	33.7	33.7
Specific Volume, scf/lb	13.3	13.3	13.3

Notes:

1. The emissions estimates shown in the table above are per stack.
2. The dry air composition used is 0.93% Ar, 78.03% N2 and 20.99% O2
3. Standard conditions are defined as 60 F, 14.696 psia. Norm conditions are defined as 0 C, 1.103 bar
4. The CTG performance is a General Electric GTPC estimate.
5. The VOC oxidation rates are Black & Veatch estimates based on typical data
6. UHC calculations do not include the effects of oxidation in the CO catalyst. The VOC/UHC ratio is assumed to be 20% for natural gas firing (typical for GE turbines).
7. The front half catch of particulate emissions is assumed to be half the amount of the front and back half catch particulates. The assumption that 100% SO3 is converted to ammonium sulfates results in "worst case" particulate emissions.

9. The SO2 oxidation rate was assumed to be 30%.

SR4/2 Preparer: J.Arthur Filepath: c:_project\patrick\tracy\emission2-8.xls]input Reviewer: P.Exod

ATTACHMENT C

SJVAPCD BACT GUIDELINES

TABLES I-1& I-2 OF CARB'S SEPTEMBER, 1999 GUIDANCE FOR POWER PLANT SITING AND BEST AVAILABLE CONTROL TECHNOLOGY

San Joaquin Valley
Unified Air Pollution Control District

Best Available Control Technology (BACT) Guideline 3.4.7*

Last Update: November 27, 2000

Emission Unit: **Gas Fired Turbine - ≥ 150 MW , Uniform Load, without Heat Recovery**

Pollutant	Achieved in Practice or contained in SIP	Technologically Feasible	Alternate Basic Equipment
NOx		1. 2.5 ppmvd** @ 15% O_2, based on a one-hour average (high temperature Selective Catalytic Reduction (SCR)). 2. 3.0 ppmvd** @ 15% O_2, based on a three-hour average (high temp SCR). 3. 3.75 ppmvd** @ 15% O_2, based on a three-hour average (high temp SCR). 4. 5.0 ppmvd** @ 15% O_2, based on a three-hour average (high temp SCR). 5. 9.0 ppmvd** @ 15% O_2, based on a three-hour average (dry Low-NOx combusters).	
CO		1. 6.0 ppmvd** @ 15% O_2, three-hour average (Oxidation catalyst) 2. 7.5 ppmvd** @ 15% O_2, three-hour average 3. 11.0 ppmvd** @ 15% O_2, three-hour average	
VOC		1. 0.6 ppmvd** @ 15% O_2, three-hour average (Oxidation catalyst) 2. 1.3 ppmvd** @ 15% O_2, three-hour average 3. 2.0 ppmvd** @ 15% O_2, three-hour average 4. 5.3 ppmvd** @ 15% O_2, three-hour average	
PM10		Air inlet cooler/filter, lube oil vent coalescer (or equal) and either PUC-regulated natural gas, LPG, or non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf.	
SOx		PUC-regulated natural gas, LPG, or Non-PUC-regulated gas with ≤ 0.75 grams S/100 dscf.	

**** Except during startup and shutdown**
***This is a Summary Page for this Class of Source - Permit Specific BACT Determinations on Next Page(s)**

Table I-1: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Simple-Cycle Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
5 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 3-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

Table I-2: Summary of BACT for the Control of Emissions from Stationary Gas Turbines Used for Combined-Cycle and Cogeneration Power Plant Configurations

NO_X	CO	VOC	PM_{10}	SO_X
2.5 ppmvd @ 15% O_2, 1-hour rolling average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	6 ppmvd @ 15% O_2, 3-hour rolling average	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf	An emission limit corresponding to natural gas with fuel sulfur content of no more than 1 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)

The basis for the BACT emission levels in Table I-2 for combined-cycle and cogeneration power plant configurations is as follows:

- for NO_X, the most stringent emission level deemed BACT by the South Coast Air Quality Management District, recognized as demonstrated in practice by the United States Environmental Protection Agency (U.S. EPA), and the most stringent BACT level proposed for six major power plant projects either approved or currently under review;

- for CO, a reasonable level of emissions based on previous BACT requirements, emission levels achieved in practice, and BACT levels proposed for major power

:ed

ATTACHMENT D

TOP DOWN BACT ANALYSIS

Top-Down BACT Analysis for N-4597-1-0 and N-4597-2-0:

1. Applicability:

Pursuant to Rule 2201, sections 4.1.1 and 4.2.1, BACT is required for all pollutants emitted by a new emissions unit or modification of an existing emissions unit, which results in an adjusted increase in permitted emissions (AIPE) greater than 2.0 lb/day as defined in Section 4.3, except for carbon monoxide (CO) emissions in CO attainment areas if the post-project stationary source potential to emit for CO ($SSPE2_{CO}$) is less than 200,000 lb/yr.

The calculations contained in Section VII of the application review for this permit unit indicate that Best Available Control Technology (BACT) is required for NO_X, volatile organic compounds (VOC), sulfur oxides (SO_X) and particulate matter less than 10 microns (PM_{10}), because the potential to emit (PE) these pollutants exceeds 2 lb/day. BACT is not required for CO because the $SSPE2_{CO}$ does not exceed 200,000 lb/yr.

2. BACT Guidance:

Per District BACT Policy APR 1305 (11/09/99), a Top-Down BACT analysis shall be performed as a part of the application review for each emission unit subject to the BACT requirements pursuant to the District's NSR Rule. The District BACT Clearinghouse currently contains BACT Guideline 3.4.7, which is applicable to simple cycle, large frame industrial turbines rated greater than or equal to 150 MW. The turbines proposed for this project are simple cycle, large frame industrial turbines. However, the turbine proposed for this project is rated at 84.4 MW. Moreover, research indicates that industrial frame turbines are widely available in the 50 MW and higher category. Therefore, pursuant to the District's BACT policy, a top down BACT analysis will be performed to **revise** BACT Guideline 3.4.7 to change the equipment rating to include simple cycle, industrial frame turbines greater than or equal to 50 MW and clarify emission control technology limits.

In order to ensure that all practically applicable control measures are considered during this analysis, the California Air Resources Board, U.S. Environmental Protection Agency, Bay Area Air Quality Management District, and South Coast AQMD BACT databases, as well as the District's BACT clearinghouse were consulted. Also, the information and recommendations contained in the California Air Resources Board's September 1999 Guidance for Power Plant Siting and Best Available Control Technology document, which is intended to provide emission control technology guidance for power generation facilities with capacities of 50 MW and greater, were considered. No other emission control technologies were found that differed significantly from those already listed in existing District BACT Guideline 3.4.7. Therefore, information will be cited from this guideline without further analysis.

3. Top Down BACT Analysis:

PM_{10} Emissions:

PM_{10} emissions are due to incomplete combustion of natural gas, formation of sulfates from sulfur in the fuel and oil mist from the lube oil cooler and accumulator vents.

Step 1 - Identify All Possible Control Technologies

Air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with ≤ 0.75 grains-S/100 scf.

Step 2 - Eliminate Technologically Infeasible Options

The above option is technologically feasible for this class and category of source.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Since there is only one control option listed, ranking is not necessary.

Step 4 - Cost Effectiveness Analysis

The applicant has proposed to use of an air inlet cooler/filter, a lube oil vent coalescer, and natural gas with a sulfur content not exceeding 0.25 grains/100 scf. Since the applicant has proposed the most effective control technology, a cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT is satisfied by the use of an air inlet cooler/filter, lube oil vent coalescer (or equal), and either PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with ≤ 0.75 grains-S/100 scf.

<u>SO_X Emissions</u>:

SO_X emissions are due to oxidation of sulfur present in the natural gas fuel.

Step 1 - Identify All Possible Control Technologies

PUC-regulated natural gas, LPG, or non-PUC-regulated natural gas with ≤ 0.75 grains-S/100 scf.

Step 2 - Eliminate Technologically Infeasible Options

The above option is technologically feasible for this class and category of source.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

Since there is only one control option listed, ranking is not necessary.

Step 4 - Cost Effectiveness Analysis

The applicant has proposed to use natural gas with a sulfur content not exceeding 0.75 grains/100 dscf. Therefore, a cost effectiveness analysis is not required.

Step 5 - Select BACT

BACT is satisfied by the use of natural gas fuel with a sulfur content not exceeding 0.75 gr/100 scf.

<u>NO_X Emissions</u>:

NO_X emissions are due to oxidation of nitrogen in the combustion air and nitrogen compounds in the fuel.

Step 1 - Identify All Possible Control Technologies

- 2.5 ppmvd @ 15% O_2 based on a 1 hour average (high temperature Selective Catalytic Reduction (SCR)), except startup and shutdown.
    - 3.0 ppmvd @ 15% O_2 based on a 3 hour average (high temperature SCR), except startup and shutdown.
    - 3.75 ppmvd @ 15% O_2 based on a 3 hour average (high temperature SCR), except startup and shutdown.

- 5.0 ppmvd @ 15% O_2 based on a 3 hour average (high temperature SCR), except startup and shutdown.

- 9.0 ppmvd @ 15% O_2 (dry low-NO_X combustors), except startup and shutdown.

Step 2 - Eliminate Technologically Infeasible Options

Consistent compliance with NO_X performance levels equal to or less than 9.0 ppmvd @ 15% O_2 cannot be achieved exclusively through the use of dry-low NO_X combustors. Additional add-on control technology such as water/steam injection (wet controls), SCR with ammonia injection, XONON, SCONOx, or selective non-catalytic reduction (SNCR) is required. The use of water/steam injection, XONON, SNCR, SCONOx, and high temperature selective catalytic reduction (SCR) to achieve NO_x performance levels less than 5.0 ppmvd @ 15% O_2 are all eliminated as technologically infeasible for the following reasons:

Water/Steam Injection: This technology can reduce NO_x using conventional combustors to 25 ppmvd @ 15% O_2, however, the Tracy Peaker Project is proposed with DLN combustors capable of reducing NO_X to 9 ppmvd @ 15% O_2.

XONON: This process uses a proprietary flameless process in which fuel and air react on the surface of catalyst in the turbine combustor to produce energy in the form of hot gases. To date, however, commercialization of this technology on GE Frame 7 size combustion turbines such as proposed by Tracy Peaker Project has not been developed, nor is available at this time.

Selective Non-Catalytic Reduction (SNCR): The exhaust temperature at the exit of the proposed CTG is approximately 1,000 °F, which is too low for SNCR type systems that require operating temperatures in the range of 1,500 to 1,900 degrees F.

SCONOx: This process utilizes a coated oxidation catalyst and chemical reactor to remove both NO_X and CO and is required to operate in a temperature range between 550 to 700 °F, which is well below the 1,000 °F exhaust temperature at the exit of the proposed CTG.

<u>High Temperature SCR to achieve NO_x levels below 5.0 ppmvd @ 15% O_2:</u> The control efficiency of a SCR system with ammonia injection is directly proportional to reactor bed inlet temperature. High temperature "zeolite" SCR catalysts have been developed that permit continuous SCR operation at temperatures as high as 1,000 °F; however, for maximum NO_x control efficiency, the optimum high temperature SCR reactor bed temperature is approximately 650 °F – 850 °F. The exhaust temperatures of General Electric large frame industrial turbines are approximately 1,000 °F. Due to the high exhaust temperatures, manufacturers of high temperature SCR systems will only guarantee a NO_x performance level of 5.0 ppmvd @ 15% O_2 for large frame industrial turbines operated in simple cycle mode.

The only way to achieve NO_x emission concentration levels less than 5.0 ppmvd is to use a heat recovery device between the turbine and the SCR reactor bed to reduce exhaust gas temperature to 650 °F – 850 °F before entering the SCR reactor bed. This information is consistent with ARB guidelines which state "the high exhaust temperatures approaching 1,100 degrees F" of industrial frame gas turbines (such as GE industrial frame series) "may require case-by-case evaluation regarding the feasibility of NO_X control through selective catalytic reduction." Moreover, the use of a heat recovery device would change the scope of this BACT guideline, which is intended for turbines without heat recovery.

Research was conducted throughout the State of California and other Air Districts to determine emission performance levels for this class and category of source [Simple Cycle Gas Fired Turbine ≥ 50 MW]. No large frame industrial turbines rated greater than or equal to 50 MW and operated in simple cycle mode with NO_x emissions lower than 5.0 ppmvd @ 15% O_2 were found. Therefore, NO_x emissions concentration levels below 5.0 ppmvd @ 15% O_2 are not technologically feasible for this class and category of source at this time and will be removed from consideration.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 5.0 ppmvd @ 15% O_2 based on a 3 hour average (high temperature SCR), except startup and shutdown.

2. 9.0 ppmvd @ 15% O_2 (dry low-NO_X combustors), except startup and shutdown.

Step 4 - Cost Effectiveness Analysis

Since the applicant is proposing to use the most effective NO_x control technology listed in step 3, a cost effectiveness analysis is not required.

Step 5 - Select BACT

5.0 ppmvd @ 15% O_2 based on a 3 hour average (high temperature SCR), except startup and shutdown.

<u>VOC Emissions</u>:

VOC emissions result from incomplete combustion of the fuel.

Step 1 - Identify All Possible Control Technologies

- 0.6 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
- 1.3 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
- 2.0 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
- 5.3 ppmvd @ 15% O_2 based on a 3 hour average, except startup and shutdown.

Step 2 - Eliminate Technologically Infeasible Options

The above options are technologically feasible for the proposed equipment.

Step 3 - Rank Remaining Control Technologies by Control Effectiveness

1. 0.6 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
2. 1.3 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
3. 2.0 ppmvd @ 15% O_2 based on a 3 hour average (Oxidation catalyst), except startup and shutdown.
4. 5.3 ppmvd @ 15% O_2 based on a 3 hour average, except startup and shutdown.

Step 4 - Cost Effectiveness Analysis

Control options 1 and 2
The cost-effectiveness of the use of oxidation catalyst will be evaluated on the basis of reducing VOC emissions from an uncontrolled level of 2.81 lb/hr (from BACT analysis performed of project S1001194) to 0.76 lb/hr (equivalent to 0.6 ppmvd @ 15% O_2 for the proposed turbine's heat input rate of 990.6 MMbtu/hr). Since the capital equipment cost for an oxidation catalyst system to achieve a VOC emission concentration of 1.3 ppmvd @ 15% O_2 is only slightly lower than a 0.6 ppmvd system, it is assumed that if a 0.6 ppmvd system is not cost effective, then a 1.3 ppmvd system will also not be cost effective because of lower VOC emission reductions.

Annual emissions will be calculated for continuous operation of 8,000 hours/year at 100% load and an ambient temperature of 59 °F. Capital costs associated with an oxidation catalyst system will be annualized for a project life of ten years per District policy. Note: although the oxidation catalyst is expected to need replacement after three years, catalyst replacement costs are not included in the ten year life. This will provide a more conservative cost effectiveness analysis for this review as inclusion of the replacement catalyst cost will only increase the annualized cost-per-ton of pollutant controlled.

Controlled VOC emissions @ Full Load Operation

VOC = (2.81 – 0.76) lb/hr × 8,000 hrs/yr = 16,400 lb/yr = 8.2 ton/yr

Costs
Data form the BACT analysis performed for project S1001194 indicates that the direct capital cost of an oxidation catalyst system (including reactor housing and controls and instrumentation) for a 165 MW General Electric model PG 7121 turbine capable of achieving a VOC emission concentration of 0.6 ppmvd @ 15% O_2 is $ 1,019,000. As a rough estimate, this cost will be scaled down to a level appropriate for an 84.4 MW turbine using the "sixth tenths" rule as follows:

$$\begin{aligned} Cost_{84.4MW} &= Cost_{165MW} \times (84.4\ MW \div 165\ MW)^{0.6} \\ &= \$1,019,000 \times (84.4 \div 165)^{0.6} \\ &= \$681,537 \end{aligned}$$

$$\begin{aligned} \text{Annualized Cost} &= \text{Capital Cost over 10 years} \\ &= \$681,537 \times 0.1627 \\ &= \$110,886 \text{ per year} \end{aligned}$$

Cost per ton	=	\$110,886/year ÷ 8.2 ton of VOC reduced/yr
	=	\$15,523/ton of VOC reduced

Therefore, the use of control technology to achieve VOC emission concentration levels of 0.6 ppmvd and 1.3 ppmvd is not cost-effective. Therefore, control options 1 and 2 are eliminated from consideration at this time.

Control option 3
The applicant is proposing to use technology listed in control 3, therefore a cost effectiveness analysis is not required.

Control option 4
The applicant is proposing to use control technology more stringent than that listing in control option 4; therefore, a cost effectiveness analysis is not required.

Step 5 - Select BACT

The most effective control measure not eliminated in Steps 2 and 4 above is a VOC emission concentration of 2.0 ppmvd @ 15% O_2 based on a 3 hour average, except startup and shutdown. The applicant is proposing this VOC emission level; therefore, the applicant's proposal satisfies BACT.

ATTACHMENT E

Interpollutant Offset Ratio Analysis

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August 2, 2001

Memo To: Doug Wheeler
GWF Power Systems Company

From: David Deckman David Deckman

Subject: Interpollutant Offset Ratio Analysis for GWF Tracy Project

As you requested, attached is an analysis of the interpollutant offset ratio for using sulfur oxides (SOx) Emission Reduction Credits to offset emissions of respirable particulate matter (PM_{10}). GWF Energy LLC is proposing to use SOx ERCs, which were purchased from Newark Sierra Paperboard Corporation in Stockton, to offset PM_{10} from the proposed Tracy Peaker Plant (TPP). The distance between the Newark Sierra facility and the proposed power plant project is greater than 15 miles. Our analysis indicates that the appropriate interpollutant ratio is 2.0 to 1.0, and that the overall offset ratio, including the adjustment for distance between the proposed project and the source of the ERCs, would be 2.5 to 1.0. This analysis is consistent with those approved by the San Joaquin Valley Unified Air Pollution Control District for other projects.

Please be aware that Section 4.2.5.3 of SJVUAPCD Rule 2201 (New and Modified Stationary Source Review) allows the use of interpollutant offsets only if the project will not cause violations of the ambient air quality standards. Because ambient PM_{10} concentrations in the San Joaquin Valley currently exceed the state and federal standards, the SJVUAPCD is accepting a demonstration that the project would not cause PM_{10} ambient concentrations in excess of the significance criteria in Title 40 Code of Federal Regulations Part 51.165(b)(2). These thresholds are 5 micrograms per cubic meter ($\mu g/m^3$) and 1.0 $\mu g/m^3$ for the 24-hour and annual averaging periods, respectively. It is our understanding that an air quality impact analysis will be prepared for the Application for Certification for this project.

If you have any questions regarding this analysis, please feel free to contact us.

attachment

INTERPOLLUTANT OFFSET RATIO ANALYSIS FOR THE GWF ENERGY LLC TRACY PEAKER PLANT

GWF Energy LLC (GWF) proposes to use sulfur oxides (SOx) Emission Reduction Credits (ERCs) to offset emissions of respirable particulate matter (PM_{10}) from its proposed Tracy Peaker Plant in Tracy, California. GWF owns ERC Certificate No. N-256-5 and has an option to purchase additional ERCs from Certificate No. N-130-5 from Newark Sierra Paperboard Company. These certificates were issued by the San Joaquin Valley Unified Air Pollution Control District (SJVUAPCD) for SOx emission reductions that were originally generated at the Newark Sierra Paperboard Company's facility at 800 West Church Street in Stockton, California. SJVUAPCD Rule 2201, Section 4.2.5.3 provides:

> *Interpollutant offsets may be approved by the APCO on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, in accordance with the provisions of Section 4.3.2 of this rule, that the emission increases from the new or modified source will not cause or contribute to a violation of an ambient air quality standard. In such cases, the APCO shall, based on an air quality analysis, impose offset ratios equal to or greater than the requirements, of this rule.*

GWF will provide a demonstration that the emission increases associated with the project will not cause or contribute to a violation of an ambient air quality standard. This analysis does not address those impacts.

This analysis provides a technical rationale for an appropriate SOx-to-PM_{10} interpollutant ratio, as well as the overall offset ratio to reflect the distance between the source providing the offsets and the proposed project.

Interpollutant Ratio

To develop an interpollutant offset ratio for SOx and PM_{10}, this analysis uses (1) a speciated linear rollback analysis using ambient monitoring data from San Joaquin County, in which both the proposed GWF project and the Newark Sierra facility are located; (2) emission inventory data in San Joaquin County; and (3) the results of Chemical Mass Balance (CMB) modeling at a location in the northern region of the San Joaquin Valley Air Basin. The approach is based on a simple box model that ignores transport and deposition; assumes that the box is the size of San Joaquin County; and assumes that the ambient pollutant concentrations in the box (San Joaquin County) can be represented by the values reported for the Hazelton Street and Wagner-Holt School monitoring stations in San Joaquin County. These are the only monitoring stations in

San Joaquin County that have the data required for this analysis. The interpollutant ratio calculations described below are shown in Attachment 1.

The actual, annual average nitrate, sulfate, chloride, and total PM_{10} ambient air measurements were used to partially speciate the PM_{10}. The ambient monitoring data were reported by the Air Resources Board (ARB) for monitoring stations located on Hazelton Street and at the Wagner-Holt School in Stockton for 1997 and 1998, the most recent years for which the speciated PM_{10} were available. According to ARB staff, speciation of the PM_{10} samples was discontinued at these monitoring stations at the end of 1998.

The unspeciated balance of the PM_{10} (after subtracting the ammonium sulfate, ammonium nitrate, and ammonium chloride from total PM_{10}) is split between direct-combustion-related PM_{10} (fuel combustion and mobile sources) and other direct PM_{10} sources. The contribution from direct-combustion-related PM_{10} is based on Chemical Mass Balance (CMB) modeling performed for the District's PM_{10} Attainment Demonstration Plan. CMB modeling was conducted by the ARB for several locations within the San Joaquin Valley for annual average conditions and maximum 24-hour conditions in support of the District's attainment plan. Annual analyses were performed for locations in Bakersfield, Corcoran, Fresno, and Visalia. Analyses of 24-hour events were performed for locations in Bakersfield, Corcoran, Fresno, Hanford, Kettleman City, Modesto, and Oildale. The nearest modeled site to the proposed GWF project is Modesto. As indicated, an annual analysis was not performed for the Modesto site, and the annual sites are in the central and southern San Joaquin Valley. Thus, the results of the 24-hour analysis were to determine the contribution from direct-combustion-related PM_{10}. The CMB modeling evaluated the contribution of specific source categories. The "mobile" category represents the contribution from mobile and other combustion sources, such as those proposed for the GWF project. In this case, the CMB modeling found that the mobile category contributed 19.28 micrograms per cubic meter ($\mu g/m^3$) out of the total PM_{10} concentration of 160 $\mu g/m^3$ for the January 20, 1994 design episode. A table from the attainment plan showing these values is attached (see Attachment 2). Thus, the direct-combustion contribution was assumed to be 12.1 percent (i.e., 19.28/160). Karen Magliano, Manager of the Particulate Matter Analysis Section of the ARB, confirmed that earlier CMB modeling for 1993 showed a similar result for an annual average analysis at Modesto. In this case, the "mobile" category contributed 4.73 $\mu g/m^3$ out of the total annual PM_{10} concentration of 42 $\mu g/m^3$, or approximately 11 percent (see Attachment 2). The results of the annual modeling were discussed in the District's attainment plan, but these details are not presented in the plan.

Next, since direct PM_{10} emissions from combustion sources (gas turbines) are being offset, it was determined how many $\mu g/m^3$ of ambient PM_{10} are associated with 1 ton/year of direct combustion PM_{10} emissions by dividing the annual average direct-combustion PM_{10} concentration by the total annual PM_{10} emissions in San Joaquin County. A similar calculation was performed for sulfur dioxide by dividing the annual average sulfate concentration by the annual SO_2 emissions in San Joaquin County. The inventory data were obtained from the ARB website (http://www.arb.ca.gov/app/emsinv/emssumcat.php). The daily values from this inventory were multiplied by 365 to compute the annual values. Total PM_{10} and SOx inventories were calculated for the years considered in our analysis. Inventory data were available from the ARB website for 1996 and 1998, but not for 1997. The 1997 inventory was computed by interpolating between 1996 and 1997. The inventory data for San Joaquin County are shown in Attachment 3. The ratio of the $\mu g/m^3$ per ton/year values indicates the number of tons of sulfur dioxide emissions that it takes to create the same number of $\mu g/m^3$ of PM_{10} that would be created by 1 ton/year of direct-combustion PM_{10} emissions. As shown in Attachment 1, this calculation results in a 2.0 to 1 interpollutant offset ratio. The results were relatively consistent between the two monitoring stations and the two calendar years of data on which these analyses were based.

Offset Ratio

Rule 2201 does not indicate specifically how the interpollutant ratio (described above) and the distance ratio (pursuant to Section 4.2.4 of Rule 2201) should be applied. Leonard Scandura of the District's Southern Region office provided a description of how the District computes the overall offset ratio. The methodology provided by Mr. Scandura addresses sources of NOx offsets within 15 miles of the new source and more than 15 miles from the new source. Because the ERC source in this case is more than 15 miles from the GWF facility and is providing SOx ERCs, this description has been modified to address this case only. The methodology provided by Mr. Scandura is as follows (with revisions to reflect the distance relationship, transfer of SOx ERCs, and a 2.0 to 1 interpollutant offset ratio):

> *Rule 2201 includes provisions for including distance offset ratios and interpollutant offset ratios to determine the quantity of offsets required. These two offset ratios are applied independently to determine the quantity of offset required.*
>
> *The distance ratio specifies the excess amount of offsets required due to the distance between the increase in emissions and the location at which the emission reductions occurred. For example, if the distance offset ratio is 1.5:1, 100% of the fraction of the emission increase to be offset at this distance is required plus an additional 50% to account for the distance between the increase in emissions and the location of the emissions reductions.*
>
> *The interpollutant offset ratio specifies excess amount of offsets required when the emission increases and the offsets being provided are not the same pollutant. Specifically, the interpollutant offset ratio quantifies the relationship between the pollutant being emitted and the emission reductions being provided. In this case [the analysis described in this report], the interpollutant offset ratio is 2.0:1, i.e., 100% of the emission increase is required to be offset plus an additional 100% to account for the relationship between the pollutant being emitted and the emissions reduction.*
>
> *When both the distance and interpollutant offset ratios apply, the overall offset quantity required is equal to the sum of the amount being emitted and the excess amount(s) required due to the distance offset ratio plus the excess amount due to*

the interpollutant offset ratio. The computation of the resulting overall SOx for PM_{10} offset ratio is as follows:

*SOx req'd ton/year = PM_{10} ton/year + PM_{10} ton/year to be offset by SOx ERCs >15 miles away * 0.5 + PM_{10} ton/year to be offset by SOx reductions * 1.0*

SOx req'd ton/year = PM_{10} ton/year + PM_{10} ton/year (0.5) + PM_{10} ton/year (1.0)

SOx req'd ton/year = PM_{10} ton/year (1 + 0.5 + 1.0)

Thus, the combined distance and interpollutant ratio is:

SOx/PM10 = 1 + 0.5 + 1.0

Using this methodology, the overall distance and interpollutant offset ratio is as follows:

$SOx/PM_{10} = 1 + 0.5 + 1.0 = 2.5$

ATTACHMENT 1

INTERPOLLUTANT OFFSET RATIO CALCULATIONS

01-Aug-01

GWF - Tracy Peaker Plant
PM10 Interpollutant Offset Ratio Analysis

1997 Annual Average Concentrations (AAM)

Station	Total PM10 ug/m3	PM10 Nitrate ug/m3	PM10 Sulfate ug/m3	PM10 Chloride ug/m3
Stockton - Hazelton St.	29.70	3.13	1.57	0.26
Stockton - Wagner-Holt	26.10	2.64	1.47	0.25
Ion Form		NO3	SO4	Cl
Ion Molecular Weight		62.005	96.062	35.453
Combined Form		NH4NO3	(NH4)2SO4	NH4Cl
Combined Molecular Wt		80.043	132.139	53.492

Direct Combustion PM10 fraction of total ambient PM10 (source apportionment): 12.1%

Station	Total PM10 ug/m3	PM10 NH4NO3 ug/m3	PM10 (NH4)2SO4 ug/m3	PM10 NH4Cl ug/m3	PM10 Direct Combustion ug/m3	PM10 Other ug/m3
Stockton - Hazelton St.	29.70	4.04	2.16	0.39	3.59	19.51
Stockton - Wagner-Holt	26.10	3.40	2.02	0.38	3.16	17.14

1997 Annual Emissions (tons/year) - San Joaquin County

Total PM10	NOx	SOx	Combustion PM10	Other Direct PM10
17,540	32,522	2,378	1,911	15,629

		Stockton Hazelton	Stockton Wagner-Holt	Average
Direct Combustion PM10:				
1,911	tons/yr =	3.59	3.16	
1	ton/yr =	0.00188	0.00165	
SO2 -> Sulfates:				
2,378	tons/yr =	2.16	2.02	
1	ton/yr =	0.00091	0.00085	
SO2:PM10 ratio =		2.07	1.94	2.01

01-Aug-01

GWF - Tracy Peaker Plant
PM10 Interpollutant Offset Ratio Analysis

1998 Annual Average Concentrations (AAM)

Station	Total PM10 ug/m3	PM10 Nitrate ug/m3	PM10 Sulfate ug/m3	PM10 Chloride ug/m3
Stockton - Hazelton St.	29.10	2.90	1.53	0.12
Stockton - Wagner-Holt	25.50	2.28	1.49	0.09
Ion Form		NO3	SO4	Cl
Ion Molecular Weight		62.005	96.062	35.453
Combined Form		NH4NO3	(NH4)2SO4	NH4Cl
Combined Molecular Wt		80.043	132.139	53.492

Direct Combustion PM10 fraction of total ambient PM10 (source apportionment): 12.1%

Station	Total PM10 ug/m3	PM10 NH4NO3 ug/m3	PM10 (NH4)2SO4 ug/m3	PM10 NH4Cl ug/m3	PM10 Direct Combustion ug/m3	PM10 Other ug/m3
Stockton - Hazelton St.	29.10	3.75	2.11	0.18	3.52	19.55
Stockton - Wagner-Holt	25.50	2.95	2.05	0.14	3.09	17.28

1998 Annual Emissions (tons/year) - San Joaquin County

Total PM10	NOx	SOx	Combustion PM10	Other Direct PM10
17,699	32,211	2,354	1,854	15,845

		Stockton Hazelton	Stockton Wagner-Holt	Average
Direct Combustion PM10:				
1,854	tons/yr =	3.52	3.09	
1	ton/yr =	0.00190	0.00166	
SO2 -> Sulfates:				
2,354	tons/yr =	2.11	2.05	
1	ton/yr =	0.00090	0.00087	
SO2:PM10 ratio =		2.12	1.91	2.02

ATTACHMENT 2

CMB MODELING RESULTS FOR MODESTO

Modesto 24 Hour

MODESTO MOVES3B,Jol/28,BAM/JC	TOTAL	Geologic and Construction	Mobile	Organic Carbon	Vegetative Burning	Ammonium Nitrate	Associated Water	Ammonium Sulfate	Unassigned	Marine
1/20/94 Concentrations	160.00	10.35	18.28	1.41	14.45	88.98	8.00	4.54	21.88	0.07
1/20/94 Percents		6.47%	11.65%	3.40%	9.03%	41.41%	5.00%	4.21%	17.30%	0.41%
Natural Background %		5%	0%	0%	0%	0%	0%	0%	10%	100%
Natural Background Value	4.78	0.52	0.00	0.00	0.00	0.00	0.30	0.00	1.77	0.07
Regional Background %		5%	10%	10%	10%	10%	10%	5%	10%	0%
Regional Background Value	15.04	0.52	1.93	0.64	1.44	4.70	0.80	0.34	2.27	0.00
Total Background	19.30	1.03	1.93	0.54	1.44	4.70	0.80	0.34	4.04	0.07
Local Contribution (Adjusted Concentration - Background)	140.70	9.31	11.38	4.88	13.00	80.21	7.20	4.48	22.10	0.00
Ammonia Emission Estimate (%)						15%				
Ammonia Emission Estimate (ug/m3)	9.04					9.04				
Local Contribution (Without Ammonia)	131.65	9.31	17.36	4.80	13.00	61.25	7.20	4.49	22.18	0.00
Base Year 1993 Seasonal Emission Inventory PM10	31.21	11.72	1.80		4.42				31.21	
ROG	12.88			12.80						
NOx	64.23					64.23	64.23			
SOx	1.87							1.87		
Future year Seasonal Emission Inventory 2001 PM	20.08	10.06	1.16		4.00				20.06	
ROG	40.98			40.98						
NOx	40.98					40.98	40.98			
SOx	1.77							1.77		
EI/Eb Ratio for Local Rollback Projection	0.79	0.86	0.78	0.77	0.83	0.78	0.70	0.95	0.90	1.00
Projected Local	106.74	8.19	11.30	3.78	10.79	38.73	6.44	6.15	19.86	0.00
EI/Eb Ratio for Regional Rollback Projection		0.87	0.80	0.71	0.83	0.80	0.80	0.80	0.91	1.00
Projected Regional Background	12.10	0.44	1.14	0.36	1.20	5.38	0.84	0.33	2.16	0.00
Natural Background	4.26	0.52	0.00	0.00	0.00	0.00	0.00	0.00	2.17	0.07
Ammonia Emission Estimate	9.04					9.04				
2001 Projected 24-Hour (Result)	131.14	9.10	13.03	4.17	11.99	53.15	8.08	6.48	20.18	0.07
Future year Seasonal Emission Inventory 2006 PM	28.71	10.84	7.13		4.33				19.70	
ROG	33.83			33.83						
NOx	33.81					33.88	33.88			
SOx	1.88							1.88		
EI/Eb Ratio for Local Rollback Projection	0.70	0.92	0.11	0.62	0.80	0.43	0.92	1.01	0.85	1.00
Projected Local	97.61	8.67	12.28	3.04	11.44	33.03	4.90	6.63	11.01	0.00
EI/Eb Ratio for Regional Rollback Projection		0.95	0.57	0.50	0.89	0.72	0.72	1.01	0.98	1.00
Projected Regional Background	11.86	0.49	1.11	0.32	1.28	4.80	0.57	0.34	2.06	0.00
Natural Background	4.28	0.52	0.00	0.00	0.00	0.00	0.00	0.00	2.17	0.07
Ammonia Emission Estimate	9.04					9.04				
2006 Projected 24-Hour (Result)	124.50	1.66	13.36	3.36	12.37	45.67	9.07	6.87	16.64	0.07

CMB-F-R6.XLB:3/24/07

David Deckman

From: Karen Magliano [kmaglian@arb.ca.gov]
Sent: Monday, February 26, 2001 11:49 AM
To: ddeckman@sierraresearch.com
Subject: Modesto Annual CMB

Dave:

After a little digging, I finally managed to find a file with the annual average numbers. For Modesto in 1993, mobile sources contributed 4.73 ug/m3 out of an annual average of 42 ug/m3 (approximately 11%).

Let me know if there's anything else.

Regards, Karen

ATTACHMENT 3

EMISSIONS INVENTORY
FOR
SAN JOAQUIN COUNTY

1997 EMISSION INVENTORY FOR SAN JOAQUIN COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
FUEL COMBUSTION	ELECTRIC UTILITIES	0.17	0.07	0.65	0.89	0.65	0.20	0.12
FUEL COMBUSTION	COGENERATION	0.02	0.01	0.04	0.14	0.00	0.01	0.01
FUEL COMBUSTION	OIL AND GAS PRODUCTION (COMBUSTION)	0.15	0.03	0.05	0.26	0.17	0.02	0.01
FUEL COMBUSTION	PETROLEUM REFINING (COMBUSTION)	0.00	0.00	0.00	0.00	0.09	0.00	0.00
FUEL COMBUSTION	MANUFACTURING AND INDUSTRIAL	0.10	0.05	1.93	7.71	0.93	0.23	0.13
FUEL COMBUSTION	FOOD AND AGRICULTURAL PROCESSING	0.21	0.17	1.28	4.17	0.27	0.29	0.27
FUEL COMBUSTION	SERVICE AND COMMERCIAL	1.14	0.26	0.36	1.27	0.32	0.14	0.13
FUEL COMBUSTION	OTHER (FUEL COMBUSTION)	0.07	0.01	0.03	0.18	0.02	0.02	0.02
WASTE DISPOSAL	SEWAGE TREATMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	LANDFILLS	0.00	0.00	0.00	0.00	0.01	0.18	0.02
WASTE DISPOSAL	INCINERATORS	0.00	0.00	0.00	0.01	0.01	0.00	0.00
WASTE DISPOSAL	SOIL REMEDIATION	0.00	0.00	0.00	0.00	0.00	0.00	0.00
WASTE DISPOSAL	OTHER (WASTE DISPOSAL)	0.00	0.00	0.00	0.00	0.00	0.03	0.01
CLEANING AND SURFACE COATINGS	LAUNDERING	0.09	0.09	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	DEGREASING	2.35	1.81	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	COATINGS AND RELATED PROCESS SOLVENTS	4.09	3.91	0.00	0.02	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	PRINTING	0.28	0.28	0.00	0.00	0.00	0.05	0.04
CLEANING AND SURFACE COATINGS	ADHESIVES AND SEALANTS	0.29	0.25	0.00	0.00	0.00	0.00	0.00
CLEANING AND SURFACE COATINGS	OTHER (CLEANING AND SURFACE COATINGS)	0.02	0.01	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OIL AND GAS PRODUCTION	3.38	0.58	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM REFINING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM MARKETING	1.05	1.04	0.00	0.00	0.00	0.00	0.00
PETROLEUM PRODUCTION AND MARKETING	OTHER (PETROLEUM PRODUCTION AND MARKETING)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	CHEMICAL	0.74	0.51	0.00	0.01	0.28	1.40	1.00
INDUSTRIAL PROCESSES	FOOD AND AGRICULTURE	1.69	1.56	0.00	0.01	0.07	1.82	0.89
INDUSTRIAL PROCESSES	MINERAL PROCESSES	0.00	0.00	0.00	0.00	0.09	2.24	1.25
INDUSTRIAL PROCESSES	METAL PROCESSES	0.00	0.00	0.09	0.01	0.02	0.00	0.00
INDUSTRIAL PROCESSES	WOOD AND PAPER	0.00	0.00	0.00	0.06	0.00	0.22	0.12
INDUSTRIAL PROCESSES	GLASS AND RELATED PRODUCTS	0.03	0.02	0.13	3.46	0.95	0.40	0.35
INDUSTRIAL PROCESSES	ELECTRONICS	0.03	0.01	0.00	0.00	0.00	0.00	0.00
INDUSTRIAL PROCESSES	OTHER (INDUSTRIAL PROCESSES)	0.03	0.02	0.00	0.00	0.03	0.03	0.02
SOLVENT EVAPORATION	CONSUMER PRODUCTS	5.42	4.49	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS	2.02	1.96	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	PESTICIDES/FERTILIZERS	2.93	2.93	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	ASPHALT PAVING / ROOFING	0.33	0.79	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	REFRIGERANTS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SOLVENT EVAPORATION	OTHER (SOLVENT EVAPORATION)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	RESIDENTIAL FUEL COMBUSTION	2.12	0.93	12.22	1.21	0.06	2.05	1.92
MISCELLANEOUS PROCESSES	FARMING OPERATIONS	66.61	5.33	0.00	0.00	0.00	22.91	10.42
MISCELLANEOUS PROCESSES	CONSTRUCTION AND DEMOLITION	0.00	0.00	0.00	0.00	0.00	6.40	3.13
MISCELLANEOUS PROCESSES	PAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	18.48	8.91
MISCELLANEOUS PROCESSES	UNPAVED ROAD DUST	0.00	0.00	0.00	0.00	0.00	19.31	11.47
MISCELLANEOUS PROCESSES	FUGITIVE WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	4.19	1.83
MISCELLANEOUS PROCESSES	FIRES	0.01	0.00	0.06	0.00	0.00	0.01	0.01

1997 EMISSION INVENTORY FOR SAN JOAQUIN COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
MISCELLANEOUS PROCESSES	WASTE BURNING AND DISPOSAL	3.51	2.09	19.58	0.55	0.00	3.13	3.07
MISCELLANEOUS PROCESSES	UTILITY EQUIPMENT	0.00	0.00	0.00	0.00	0.00	0.00	0.00
MISCELLANEOUS PROCESSES	COOKING	0.10	0.01	0.00	0.00	0.00	0.29	0.21
MISCELLANEOUS PROCESSES	OTHER (MISCELLANEOUS PROCESSES)	0.00	0.00	0.00	0.00	0.00	0.30	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY PASSENGER (LDA)	15.74	14.59	125.67	11.96	0.11	0.34	0.33
ON-ROAD MOTOR VEHICLES	LIGHT AND MEDIUM DUTY TRUCKS	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 1 (LDT1)	4.24	3.94	42.43	3.76	0.02	0.07	0.07
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 2 (LDT2)	3.45	3.14	39.37	5.55	0.04	0.21	0.20
ON-ROAD MOTOR VEHICLES	MEDIUM DUTY TRUCKS (MDV)	3.21	2.55	33.51	3.73	0.04	0.11	0.11
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 1 (LHDV1)	2.40	2.24	37.60	2.01	0.01	0.01	0.01
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 2 (LHDV2)	0.10	0.09	1.29	0.24	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY GAS TRUCKS (MHDV)	2.35	1.90	36.59	1.61	0.00	0.01	0.01
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY GAS TRUCKS (HHDV)	0.77	0.71	14.46	0.48	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL TRUCKS (ALL)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 1 (LHDV1)	0.01	0.01	0.02	0.11	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 2 (LHDV2)	0.02	0.02	0.05	0.29	0.01	0.01	0.01
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY DIESEL TRUCKS (MHDV)	0.13	0.11	0.68	2.99	0.10	0.11	0.11
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY DIESEL TRUCKS (HHDV)	0.92	0.81	3.65	14.32	0.49	0.46	0.46
ON-ROAD MOTOR VEHICLES	MOTORCYCLES (MCY)	0.50	0.48	2.15	0.17	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL URBAN BUSES (UB)	0.01	0.01	0.03	0.15	0.01	0.00	0.00
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS URBAN BUSES (UB)	0.03	0.03	0.73	0.06	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	SCHOOL BUSES (SB)	0.04	0.03	0.77	0.12	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	MOTOR HOMES (MH)	0.09	0.09	1.72	0.39	0.00	0.00	0.00
ON-ROAD MOTOR VEHICLES	OTHER (ON-ROAD MOTOR VEHICLES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	AIRCRAFT	0.47	0.42	4.24	0.22	0.03	0.02	0.02
OTHER MOBILE SOURCES	TRAINS	0.20	0.18	0.51	3.31	0.05	0.07	0.07
OTHER MOBILE SOURCES	SHIPS AND COMMERCIAL BOATS	0.09	0.08	0.23	0.28	0.41	0.05	0.05
OTHER MOBILE SOURCES	RECREATIONAL BOATS	6.94	6.40	52.29	1.83	0.04	0.23	0.21
OTHER MOBILE SOURCES	OFF-ROAD RECREATIONAL VEHICLES	0.41	0.38	2.46	0.04	0.00	0.00	0.00
OTHER MOBILE SOURCES	OFF-ROAD EQUIPMENT	2.21	1.94	18.62	6.42	0.65	0.42	0.42
OTHER MOBILE SOURCES	FARM EQUIPMENT	1.43	1.26	8.47	9.49	1.12	0.60	0.60
OTHER MOBILE SOURCES	FUEL STORAGE AND HANDLING	0.00	0.00	0.00	0.00	0.00	0.00	0.00
OTHER MOBILE SOURCES	OTHER (OTHER MOBILE SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	GEOGENIC SOURCES	0.00	0.00	0.00	0.00	0.00	0.03	0.00
NATURAL SOURCES	WILDFIRES	0.02	0.01	0.07	0.00	0.00	0.01	0.01
NATURAL SOURCES	WINDBLOWN DUST	0.00	0.00	0.00	0.00	0.00	0.00	0.00
NATURAL SOURCES	OTHER (NATURAL SOURCES)	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ALL SOURCES		143.35	70.47	464.69	89.10	6.52	67.72	48.96

PM10 - FUEL COMBUSTION	2.59
PM10 - MOBILE SOURCES	2.65
PM10 - ALL SOURCES	48.05

1998 EMISSION INVENTORY FOR SAN JOAQUIN COUNTY

CATEGORY	SUBCATEGORY	EMISSIONS (TONS PER DAY) TOG	ROG	CO	NOX	SOX	PM	PM10
FUEL COMBUSTION	ELECTRIC UTILITIES	0.24	0.07	1.22	1.02	0.65	0.23	0.03
FUEL COMBUSTION	COGENERATION	0.02	0.01	0.05	0.14	0	0.01	0
FUEL COMBUSTION	OIL AND GAS PRODUCTION (COMBUSTION)	0.16	0.03	0.08	0.17	0.17	0.02	0.01
FUEL COMBUSTION	PETROLEUM REFINING (COMBUSTION)	0	0	0	0	0	0	0
FUEL COMBUSTION	MANUFACTURING AND INDUSTRIAL	0.09	0.04	1.85	3.50	0.91	0.21	0.09
FUEL COMBUSTION	FOOD AND AGRICULTURAL PROCESSING	0.22	0.17	1.29	3.97	0.27	0.29	3.26
FUEL COMBUSTION	SERVICE AND COMMERCIAL	0.14	0.05	0.33	1.31	0.02	0.14	0.13
FUEL COMBUSTION	OTHER (FUEL COMBUSTION)	0	0	0	0	0	0	0
WASTE DISPOSAL	SEWAGE TREATMENT	0	0	0	0	0	0	0
WASTE DISPOSAL	LANDFILLS	0	0	0	0	0	0.19	0
WASTE DISPOSAL	INCINERATORS	0	0	0	0.05	0	0	0
WASTE DISPOSAL	SOIL REMEDIATION	0	0	0	0	0	0	0
WASTE DISPOSAL	OTHER (WASTE DISPOSAL)	0	0	0	0	0	0.03	0
CLEANING AND SURFACE COATINGS	LAUNDERING	0.09	0	0	0	0	0	0
CLEANING AND SURFACE COATINGS	DEGREASING	2.41	1.86	0	0	0	0	0
CLEANING AND SURFACE COATINGS	COATINGS AND RELATED PROCESS SOLVENTS	4.01	3.69	0	0	0	0	0
CLEANING AND SURFACE COATINGS	PRINTING	0.28	0.28	0	0	0	0.05	0.04
CLEANING AND SURFACE COATINGS	ADHESIVES AND SEALANTS	0.24	0.21	0	0	0	0	0
CLEANING AND SURFACE COATINGS	OTHER (CLEANING AND SURFACE COATINGS)	0.02	0.01	0	0	0	0	0
PETROLEUM PRODUCTION AND MARKETING	OIL AND GAS PRODUCTION	3.15	0.92	0	0	0	0	0
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM REFINING	0	0	0	0	0	0	0
PETROLEUM PRODUCTION AND MARKETING	PETROLEUM MARKETING	1.04	1.03	0	0	0	0	0
PETROLEUM PRODUCTION AND MARKETING	OTHER (PETROLEUM PRODUCTION AND MARKETING)	0	0	0	0	0	0	0
INDUSTRIAL PROCESSES	CHEMICAL	0.71	0.48	0	0.01	0.24	2.43	1.65
INDUSTRIAL PROCESSES	FOOD AND AGRICULTURE	1.68	1.55	0	0.01	0.01	2.07	1.03
INDUSTRIAL PROCESSES	MINERAL PROCESSES	0	0	0	0	0.17	1.37	0.77
INDUSTRIAL PROCESSES	METAL PROCESSES	0	0	0.09	0.01	0.02	0	0
INDUSTRIAL PROCESSES	WOOD AND PAPER	0	0	0	0	0	0.21	0.12
INDUSTRIAL PROCESSES	GLASS AND RELATED PRODUCTS	0.03	0.02	0.14	4.32	0.61	0.43	0.29
INDUSTRIAL PROCESSES	ELECTRONICS	0.03	0.02	0	0	0	0	0
INDUSTRIAL PROCESSES	OTHER (INDUSTRIAL PROCESSES)	0.06	0.04	0	0	0	0.02	0.02
SOLVENT EVAPORATION	CONSUMER PRODUCTS	5.32	4.47	0	0	0	0	0
SOLVENT EVAPORATION	ARCHITECTURAL COATINGS AND RELATED PROCESS SOLVENTS	2.08	2	0	0	0	0	0
SOLVENT EVAPORATION	PESTICIDES/FERTILIZERS	2.77	2.77	0	0	0	0	0
SOLVENT EVAPORATION	ASPHALT PAVING / ROOFING	0.34	0.3	0	0	0	0	0
SOLVENT EVAPORATION	REFRIGERANTS	0	0	0	0	0	0	0
SOLVENT EVAPORATION	OTHER (SOLVENT EVAPORATION)	0	0	0	0	0	0	0
MISCELLANEOUS PROCESSES	RESIDENTIAL FUEL COMBUSTION	2.16	0.95	12.11	1.22	0.06	2.03	1.9
MISCELLANEOUS PROCESSES	FARMING OPERATIONS	66.81	5.33	0	0	0	22.91	10.42
MISCELLANEOUS PROCESSES	CONSTRUCTION AND DEMOLITION	0	0	0	0	0	6.61	3.23
MISCELLANEOUS PROCESSES	PAVED ROAD DUST	0	0	0	0	0	20.61	9.15
MISCELLANEOUS PROCESSES	UNPAVED ROAD DUST	0	0	0	0	0	19.06	11.32
MISCELLANEOUS PROCESSES	FUGITIVE WINDBLOWN DUST	0	0	0	0	0	4.19	1.93
MISCELLANEOUS PROCESSES	FIRES	0.01	0	0.06	0	0	0.01	0.01

1998 EMISSION INVENTORY FOR SAN JOAQUIN COUNTY

CATEGORY	SUBCATEGORY	TOG	ROG	CO	NOX	SOX	PM	PM10
		EMISSIONS (TONS PER DAY)						
MISCELLANEOUS PROCESSES	WASTE BURNING AND DISPOSAL	3.57	2.03	15.91	0.55	0	3.19	3.13
MISCELLANEOUS PROCESSES	UTILITY EQUIPMENT	0	0	0	0	0	0	0
MISCELLANEOUS PROCESSES	COOKING	0.1	0.07	0	0	0	0.29	0.21
MISCELLANEOUS PROCESSES	OTHER (MISCELLANEOUS PROCESSES)	0	0	0	0	0	0	0
ON-ROAD MOTOR VEHICLES	LIGHT DUTY PASSENGER (LDA)	15.03	13.5	120.05	11.54	0.11	0.35	0.34
ON-ROAD MOTOR VEHICLES	LIGHT AND MEDIUM DUTY TRUCKS	0	0	0	0	0	0	0
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 1 (LDT1)	4.1	3.81	40.53	3.0	0.02	0.07	0.07
ON-ROAD MOTOR VEHICLES	LIGHT DUTY TRUCKS - 2 (LDT2)	3.44	3.11	38.4	5.64	0.04	0.22	0.21
ON-ROAD MOTOR VEHICLES	MEDIUM DUTY TRUCKS (MDV)	3.16	2.9	35.01	3.8	0.04	0.11	0.11
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS TRUCKS (ALL)	0	0	0	0	0	0	0
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 1 (LHDV1)	2.2	2.05	34.18	1.69	0.01	0.01	0.01
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY GAS TRUCKS - 2 (LHDV2)	0.1	0.09	1.21	0.23	0	0	0
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY GAS TRUCKS (MHDV)	1.8	1.67	32.03	1.47	0	0	0
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY GAS TRUCKS (HHDV)	0.64	0.59	12.01	0.4	0	0	0
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL TRUCKS (ALL)	0	0	0	0	0	0	0
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 1 (LHDV1)	0.01	0.01	0.02	0.11	0	0	0
ON-ROAD MOTOR VEHICLES	LIGHT HEAVY DUTY DIESEL TRUCKS - 2 (LHDV2)	0.02	0.02	0.65	0.29	0.01	0.01	0.01
ON-ROAD MOTOR VEHICLES	MEDIUM HEAVY DUTY DIESEL TRUCKS (MHDV)	0.12	0.11	0.65	2.84	0.09	0.1	0.1
ON-ROAD MOTOR VEHICLES	HEAVY HEAVY DUTY DIESEL TRUCKS (HHDV)	0.84	0.73	3.26	13.4	0.46	0.41	0.41
ON-ROAD MOTOR VEHICLES	MOTORCYCLES (MCY)	0.35	0.37	1.74	0.06	0	0	0
ON-ROAD MOTOR VEHICLES	HEAVY DUTY DIESEL URBAN BUSES (UB)	0.01	0.01	0.03	0.19	0.01	0	0
ON-ROAD MOTOR VEHICLES	HEAVY DUTY GAS URBAN BUSES (UB)	0.03	0.03	0.8	0.06	0	0	0
ON-ROAD MOTOR VEHICLES	SCHOOL BUSES (SB)	0.03	0.08	0.72	0.12	0	0	0
ON-ROAD MOTOR VEHICLES	MOTOR HOMES (MH)	0.03	0.07	1.64	0.38	0	0	0
ON-ROAD MOTOR VEHICLES	OTHER (ON-ROAD MOTOR VEHICLES)	0	0	0	0	0	0	0
OTHER MOBILE SOURCES	AIRCRAFT	0.46	0.43	4.38	0.22	0.03	0.02	0.02
OTHER MOBILE SOURCES	TRAINS	0.16	0.14	0.51	3.28	0.05	0.06	0.05
OTHER MOBILE SOURCES	SHIPS AND COMMERCIAL BOATS	0.08	0.07	0.23	0.28	0.41	0.05	0.05
OTHER MOBILE SOURCES	RECREATIONAL BOATS	7.09	6.54	53.16	1.9	0.04	0.23	0.21
OTHER MOBILE SOURCES	OFF-ROAD RECREATIONAL VEHICLES	0.42	0.39	2.38	0.04	0	0	0
OTHER MOBILE SOURCES	OFF-ROAD EQUIPMENT	2.13	1.87	12.48	6.32	0.67	0.42	0.41
OTHER MOBILE SOURCES	FARM EQUIPMENT	1.41	1.24	8.37	9.36	1.13	0.59	0.59
OTHER MOBILE SOURCES	FUEL STORAGE AND HANDLING	0	0	0	0	0	0	0
OTHER MOBILE SOURCES	OTHER (OTHER MOBILE SOURCES)	0	0	0	0	0	0	0
NATURAL SOURCES	GEOGENIC SOURCES	0	0	0	0	0	0	0
NATURAL SOURCES	WILDFIRES	0.01	0	0.03	0	0	0	0
NATURAL SOURCES	WINDBLOWN DUST	0	0	0	0	0	0	0
NATURAL SOURCES	OTHER (NATURAL SOURCES)	0	0	0	0	0	0	0
ALL SOURCES		143.37	68.19	415.04	85.25	6.45	88.64	48.49

PM10 - FUEL COMBUSTION	2.48
PM10 - MOBILE SOURCES	2.80
PM10 - ALL SOURCES	46.49

ATTACHMENT F

Air Quality Impact Analysis Summary Sheet

San Joaquin Valley Unified
Air Pollution Control District

MEMORANDUM

DATE: September 4, 2001

TO: Nick Peirce, AQE—Permit Services

FROM: Brian Clerico, AQS—Technical Services

SUBJECT: AAQA and RMR Modeling Results for GWF Energy (N-4597-1-0, '2-0)

As per your request, Technical Service performed a RMR and Ambient Air Quality Analysis on two 84.4 MW GE model PG 7121 EA natural gas combustion turbines (1-0, 2-0) equipped with a selective catalytic reduction system with aqueous ammonia injection and an oxidation catalyst.

This memo does not include the 382 hp diesel-fired emergency IC engine.

RMR Modeling

1995 Ventura County Emission Factors for turbine natural gas combustion were used to speciate and quantify the emissions. The emissions also include 13.19 lb/hr and 105520 lb/year of ammonia from the SCR system. Pollutant dispersion was determined from ISCST3 using the stack parameters provided by the engineer and building downwash data supplied by the applicant. The maximum annual X/Q and maximum 1-hr X/Q for the turbines occur at approximately 7000m and 1100m, respectively, from the facility fence-line. These values were used to perform the risk impact of the turbines on the nearest receptor (243m).

Device	Natural Gas Turbine 1-0	Natural Gas Turbine 2-0	Project Total
Acute Index	0.00	0.00	0.00
Chronic Index	0.00	0.00	0.00
Cancer Risk (per million)	0.0	0.0	0.0
TBACT Required?	No	No	

AAQA

For the Ambient Air Quality Analysis, the engineer supplied the emission rates for each criteria pollutant on an hourly and annual basis. Background concentrations for the pollutants were drawn from EPA data for San Joaquin County 1999 and Fresno County (1996 for SO_x).

The results from Criteria Pollutant Modeling are as follows:

AAQA Results*

Device – NG Turbine	1 Hour	3 Hours	8 Hours.	24 Hours	Annual
CO	**Pass**	X	**Pass**	X	X
NO_x	**Pass**	X	X	X	**Pass**
SO_x	**Pass**	**Pass**	X	**Pass**	**Pass**
PM_{10}	X	X	X	**Pass****	**Pass****

* See the attached PSD spreadsheet for pollutant concentrations.
** The PM_{10} emissions for this project are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).
X = Not a designated averaging time for this pollutant.

Conclusion

The AAQA indicates that the emissions from the turbines will not have an adverse impact on the State or National AAQS.

The acute and chronic indices are not above 1.0, and the cancer risk is not above 1.0 for either turbine. Therefore, in accordance with the District's RMR policy, **the project is approved for permitting without TBACT.**

RO Time: 8.0 hours

Fill in the gray areas only

Name		Turbine 1 ISCST3 ug/M^3	Turbine 1 Emissions Lbs	Turbine 1 Concentration ug/M^3	Turbine 2 ISCST3 ug/M^3	Turbine 2 Emissions Lbs	Turbine 2 Concentration ug/M^3	En_ICE ISCST3 ug/M^3	En_ICE Emissions Lbs	En_ICE Concentration ug/M^3	Back-ground ug/m^3	TOTAL	AAQS ug/m^3	Result
		1			2			3						
NOx														
	1 HR	2.96E-01	25.25	9.41E-01	2.96E-01	25.25	9.41E-01			0.00	141.56	143.44	470	PASS
8760	ANNUAL	3.88E-03	153460.00	8.56E-03	3.88E-03	153460.00	8.56E-03			0.00	28.70	28.72	100	PASS
CO														
	1 HR	2.96E-01	20.09	7.49E-01	2.96E-01	20.09	7.48E-01			0.00	13164.50	13166.00	23000	PASS
	8 HR	5.35E-02	160.72	1.35E-01	5.35E-02	160.72	1.35E-01			0.00	9087.00	9087.27	10000	PASS
SOx														
	1 HR	2.96E-01	0.70	2.61E-02	2.96E-01	0.70	2.61E-02			0.00	39.96	40.01	655	PASS
	3 HR	1.15E-01	2.10	1.01E-02	1.15E-01	2.10	1.01E-02			0.00	26.64	26.66	1300	PASS
	24 HR	2.77E-02	16.80	2.45E-03	2.79E-02	16.80	2.46E-03			0.00	23.98	23.98	105	PASS
8760	ANNUAL	3.88E-03	5600.00	3.12E-04	3.88E-03	5600.00	3.12E-04			0.00	5.33	5.33	80	PASS
PM10														
	24 HR	2.77E-02	247.20	3.60E-02	2.79E-02	247.20	3.63E-02			0.00	155.00	155.07	50	Failed
8760	ANNUAL	3.88E-03	82400.00	4.60E-03	3.88E-03	82400.00	4.60E-03			0.00	37.70	37.71	30	Failed

** The Criteria pollutant(s) noted by a double asterisk (**) is/are below EPA's level of significance as found in 40 CFR Part 51.165 (b)(2).

EPA'S LEVELS OF SIGNIFICANCE FOR INCREASED CRITERIA POLLUTANT EMISSIONS
40 CFR PART 51.165 (b)(2)

POLLUTANT	ANNUAL	AVERAGING TIME (HOURS) 24	8	3	1
SO_2	1.0 μg/m³	5 μg/m³		25 μg/m³	
PM_{10}	1.0 μg/m³	5 μg/m³			
NO_2	1.0 μg/m³				
CO	1.0 μg/m³		500 μg/m³		2000 μg/m³

AIRData Values
CONVERSION FACTORS:
ppm$_v$ to ug/m³

CO	1165.00
NO_2	1913.00
SO_2	2664.00

ATTACHMENT G

Stationary Source Compliance Certification Letter

GWF

GWF ENERGY LLC

September 4, 2001

SEP 04

Mr. James Swaney, Permit Services Manager
San Joaquin Valley Air Pollution Control District
4230 Kieman Avenue, Suite 130
Modesto CA 95356-9322

RE: Certification of Compliance

Dear Mr. Swaney:

In accordance with District Rule 2201, New and Modified Stationary Source Review, Section 4.14.3, GWF Energy LLC and GWF Power Systems Company hereby certify that all major stationary sources owned and operated in California by said companies are in compliance or on a schedule for compliance with all applicable emission limitations and standards.

Thank you for your time and consideration regarding this matter.

Respectfully,

GWF Energy LLC

Mark Kehoe
Director, Environmental and Safety Programs

cc D. Wheeler, GWF

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