PLACER COUNTY AIR POLLUTION CONTROL DISTRICT
PRELIMINARY DETERMINATION OF COMPLIANCE

ROSEVILLE ENERGY PARK
ROSEVILLE ELECTRIC

160 Megawatt Maximum
Electrical Power Generating Facility with
Two Natural Gas-Fired Combustion Turbines

5400 Phillip Road, Roseville, California

May 25, 2004

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Application Number:	**Application for Certification (AFC) #03-AFC-01** **District Application #AC-03-102**
Company Name:	**Roseville Electric**
Project Name:	**Roseville Energy Park**
Project Location:	**5400 Phillip Road, Roseville, California** **Assessor Parcel No. 017-100-029 and 017-100-030**
Date of Application:	**October 30, 2003 (Energy Commission Filing)** **November 6, 2003 (District Filing)**
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I. PROPOSAL

Roseville Electric has filed an application for an electrical power generating facility designated the Roseville Energy Park which is nominally rated at 125 megawatts (MW) with a maximum capability of up to 160 megawatts. Roseville Electric is the Electric Department for the City of Roseville. The proposed facility would use natural gas fired, combined cycle, combustion turbine generator technology for electrical power generation.

The proposed project location is 5400 Phillip Road, Roseville, California. The site is within the limits of the City of Roseville across the road from the Pleasant Grove Waste Water Treatment Plant.

II. INTRODUCTION

On October 30, 2003, Roseville Electric submitted an Application for Certification (AFC) #03-AFC-01 for the Roseville Energy Park to the California Energy Commission (Energy Commission). The Energy Commission has the exclusive authority to license power plants that have a generating capacity of 50 megawatts or greater. The Energy Commission is the lead agency for the project for the requirements of the California Environmental Quality ACT (CEQA).

The Placer County Air Pollution Control District (PCAPCD) participates in the process with other agencies to ensure that the project will comply with applicable rules and regulations.

Roseville Electric filed an application with the PCAPCD on November 6, 2003. The application was deemed complete on November 26, 2003. PCAPCD staff has completed an initial review and engineering analysis. A preliminary decision on whether the proposed power plant is expected to meet the requirements of applicable air rules and regulations is provided in this document which is called a Preliminary Determination of Compliance (PDOC).

The PDOC will be forwarded to the Energy Commission, the California Air Resources Board, the U.S Environmental Agency (EPA) and interest parties. The District will publish a public notice in at least one newspaper of general circulation and invite written comments for a period of thirty (30) days. The information submitted by the applicant and the PDOC will be made available for inspection at the PCAPCD's office. The comment period provides the public and other agencies the opportunity to participate in this part of the licensing process.

The Determination of Compliance (DOC) will not be finalized until the written comments on the PDOC are considered and the applicant has provided adequate demonstration that required emission offsets have been secured. The DOC will be released only after the PCAPCD Air Pollution Control Officer determines that the power plant will meet all applicable air rules and regulations and all air emission offsets have been completely identified and reviewed.

A list of acronyms used in this document is shown in Appendix A.

III. OPERATING SCHEDULE

The facility may operate up to 24 hours per day and 7 days per week. Roseville Electric has proposed the following maximum operating schedule in each quarter. These hours were utilized in determining the maximum quarterly air emissions and quantity of offsets required.

Table 1 - Power Plant Gas Turbine Operating Schedule

	1st	2nd	3rd	4th	Annual
Base load only hours	1,123	1,188	751	852	3,914
Peaking hours (duct firing)	929	559	1,347	1,246	4,081
Total startup hours	44	117	34	47	242
Total hours	2,096	1,864	2,132	2,145	8,237

Table 2 – Power Plant Auxiliary Equipment Operating Schedule					
	1st	2nd	3rd	4th	Annual
Auxiliary Boiler	140	568	143	143	995
Emergency Generator	12.5	12.5	12.5	12.5	50
Fire Pump	12.5	12.5	12.5	12.5	50
Notes: (1)Emergency generator and fire pump engines to be run for no more than 50 hours per year including maintenance and testing. These hours may be limited to 20 hours per year when CARB Diesel ATCM for Stationary Diesel Engines becomes effective.					

IV. EQUIPMENT DESCRIPTION

Roseville Electric proposes to use either two General Electric (GE) LM6000 or two Alstom GTX100 combustion turbine generators (CTGs). The GE CTGs are estimated to generate up to 47 MW each at average ambient conditions. The Alstom CTGs are estimated to generate up to 43 megawatts each, at average ambient conditions. Either design will include heat recovery steam generators (HRSGs) with duct burners. One steam turbine will provide an additional electrical generating capacity of up to 30 megawatts in the GE design and 43 megawatts in the Alstom design at ambient conditions, without operation of the HRSG duct burners. The duct burners will increase the maximum capacity, after subtracting a internal auxillary loads to 160 MW.

The major equipment at the plant include:

- Two (2) natural gas-fired, combined cycle, combustion turbine generators (CTGs). Roseville Electric proposes to use either the GE LM6000 PC Sprint or Alstom GTX100 gas turbines.

- Two (2) heat recovery steam generators (HRSG) with duct burners. The duct burners in the GE design are each rated at 255 MMBtu/hr. The duct burners in the Alstom design are each rated at 225 MMBtu/hr.

- One (1) steam turbine generator

- One (1) auxillary natural gas-fired boiler rated at 58 MMBtu/hr, 40,000 pounds per hour of steam

- One (1) 1,133 horsepower, 750 KW diesel engine standby generator.

- One (1) 300 horsepower, diesel engine fire pump.

- Two (2) 120 feet high stacks.

- One (1) cooling tower with four cells.

Gas Turbines

Gas turbines are internal combustion engines that operate with a rotary rather than a reciprocating motion. A gas turbine has three main components: a compressor, combustor and a turbine. Air is drawn in and compressed. The compressed air is fed to a combustor section along with the fuel. The mixture is ignited and burned. Hot gases are directed to the power turbine. Energy from expansion of the hot gases in the power turbine is recovered in the form of shaft horsepower. The hot exhaust gases from the combustion turbine generator flows to a heat recovery steam generator.

The heat recovery steam generators produce steam that powers the steam turbine generator. Auxiliary duct burners in the heat recovery steam generators are included to add heat and increase the electrical generation peak output of the plant.

Auxiliary Boiler

An auxiliary boiler, rated at 58 MMBtu/hr and capable of providing up to 40,000 pounds per hour (lb/hr) of saturated steam at 600 pounds per square inch gauge (psig) is proposed to provide steam when the CTGs are not operating. The boiler does not provide steam for electrical power generation. It will provide steam for HRSG for drum sparging, condenser hotwell sparging, steam turbine glands, and deaeration when the plant is offline.

V. AIR POLLUTION CONTROL EQUIPMENT DESCRIPTION

Roseville Electric has proposed using either two Alstom GTX gas turbines or two GE LM6000 gas turbines. These will be discussed separately in this section.

Alstom GTX100 Gas Turbines

Dry Low NOx Combustors

The primary mechanism by which nitrogen oxides (NOx) form in natural gas turbines is thermal NOx. Thermal dissociation during combustion and the subsequent reaction of nitrogen (N_2) and oxygen (O_2) in the air form NOx. The maximum thermal NOx formation occurs at a slightly fuel lean mixture because of excess oxygen available for the reaction.

According to the U.S. EPA, Compilation of Air Pollution Emission Factors, AP-42, the combustion process in a gas turbine can be classified as diffusion flame combustion, or lean-premix staged combustion. In the diffusion flame combustion, the fuel/air mixing and combustion take place simultaneously in the primary combustion zone. This generates regions of near-stoichiometric fuel/air mixtures where the temperatures are very high. For lean-premix combustors, fuel and air are thoroughly mixed in an initial state resulting in a uniform, lean, unburned fuel/air mixture which is delivered to a secondary stage where the combustion reaction takes place. Manufacturers use different types of fuel/air staging, including fuel staging, air staging or both; however the same staged, lean-premix principle is applied. Gas turbines using staged combustion are also referred to as Dry Low NOx combustors. These combustors are called "dry" because they do not use water or steam injection.

The proposed Alstom GTX gas turbines utilize Dry Low NOx combustors. Lower NOx emission rates are achieved by the design of the combustor and fuel injection nozzles that optimize the mixing of combustion air and fuel at peak flame temperatures.

Selective Catalytic Reduction

NOx emissions will be further reduced by installation of a selective catalytic reduction system (SCR). The SCR consists of a catalyst bed and an ammonia injection system. Both are located within the heat recovery steam generator. The ammonia reduces NO_x to N_2 and O_2 in the catalyst.

Oxidation Catalyst

Carbon monoxide (CO) and volatile organic compounds (VOCs) emissions are caused by the incomplete combustion of natural gas in the CTGs and HRSGs. Carbon monoxide occurs when there is insufficient residence time or incomplete mixing to complete the fuel oxidation. VOCs are emitted when some of the fuel remains unburned. Some of the VOCs are byproducts of the combustion.

VOCs and CO are reduced by an oxidizing catalyst installed in the heat recovery steam generator. The oxidization catalyst promotes the formation of CO_2 and H_2O.

GE LM6000 Gas Turbines

Water Injection

Roseville Electric proposes to use water injection in the GE gas turbines to reduce NOx. Small amounts of water are injected into the combustor burner flame. NOx emissions are reduced by cooling the combustion temperature.

Selective Catalytic Reduction

NOx emissions will be further reduced by installation of a selective catalytic reduction system (SCR). The SCR consists of a catalyst bed and an ammonia injection system.   Both are located within the heat recovery steam generator. The ammonia reduces NO_x to N_2 and O_2 in the catalyst.

Oxidation Catalyst

Carbon monoxide and volatile organic compounds (VOCs) emissions are caused by the incomplete combustion of natural gas in the CTGs and HRSGs. Carbon monoxide occurs when there is insufficient residence time or incomplete mixing to complete the fuel oxidation. VOCs are emitted when some of the fuel remains unburned. Some of the VOCs are byproducts of the combustion.

VOCs and CO are reduced by an oxidizing catalyst installed in the heat recovery steam generator. The oxidization catalyst promotes the formation of CO_2 and H_2O.

Auxiliary boiler

The plant design includes an auxillary boiler to be used when the plant is not generating electricity. The auxiliary boiler is to be equipped with an ultra low-NO_x burner and flue gas recirculation to control the stack NO_x concentration to not more than 9 ppmv at 3 percent oxygen and the CO concentration to not more than 50 ppmv at 3 percent oxygen.

Standby Generator Diesel Engine

The plant design includes a 750 kW, standby generator driven by a 1133 horsepower diesel engine. The generator will provide power if the facility is not operating and there is an outage on the 60kV system. The generator is designed to provide essential power to the plant but not to provide power for a "black start" or power to the grid. The application indicated the standby generator diesel engine has emissions of 7.17 grams per horsepower-hour.

The PCAPCD's BACT for NOx is 6.9 grams per horsepower-hour for an engine of this type. This emission level is achieved by engine design and is readily available from new EPA certified engines. This has been discussed with the applicant and they have agreed to use an engine meeting the 6.9 grams per horsepower- hour emission level for NOx.

Fire Pump Diesel Engine

The plant design includes a fire pump driven by a 300 horsepower diesel engine. BACT is triggered for NOx . The application indicates the engine has emissions of 5.2 grams per horsepower hour. This diesel engine meets the PCAPCD's current BACT level of 6.9 grams per horsepower hour.

VI. BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

Best Available Control Technology is defined by District Rule 502, New Source Review, as the most stringent of:

a. The most effective emission control device, emission limit, or technique, singly or in combination, which has been required or used for the type of equipment comprising such an emissions unit unless the applicant demonstrates to the satisfaction of the Air Pollution Control Officer that such limitations required on other sources have not been demonstrated to be achievable.

b. Any alternative basic equipment, fuel, process, emission control device or technique, singly or in combination, determined to be technologically feasible and cost-effective by the Air Pollution Control Officer.

c. For replacement equipment only, the emission limitation that is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts by each class or category of the source.

d. In making a BACT determination for nonattainment pollutant the Air Pollution Control Officer may consider the overall effect on other nonattainment pollutants. In some cases the lowest emission rates may be required for one or more nonattainment pollutants at the cost of not achieving the lowest emission rate for other nonattainment pollutants. The Air Pollution Control Officer shall discuss these considerations in the Preliminary Decision prepared pursuant to Section 403.

The California Air Resources Board (CARB) published the Guidance for Power Plant Siting and Best Available Control Technology (September, 1999) to address permitting issues for new power plants and identify CARB staff's determination of BACT. The following table shows CARB's BACT for combined cycle turbines.

Table 3 - CARB BACT From Guidance for Power Plant Siting and Best Available Control Technology (September, 1999)				
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)
Dry Low NOx Combustor, SCR	Oxidation Catalyst	Good combustion control and oxidation catalyst	Exclusive use of utility grade natural gas as fuel	Exclusive use of utility grade natural gas as fuel

The applicant proposes to meet the following levels if the Alstom CTGs are selected:

Table 4 - Roseville Energy Park Proposed Best Available Control Technology – Alstom GTX100				
NO_X	CO	VOC	PM_{10}	SO_X
2.0 ppmvd @ 15% O_2, 1-hour average	4 ppmvd @ 15% O_2 3-hour rolling average	2 ppmvd	Exclusive use of pipeline quality natural gas as fuel	Exclusive use of pipeline quality natural gas as fuel
Dry Low NOx Combustor, SCR	Oxidation Catalyst	Good combustion control and oxidation catalyst	Exclusive use of pipeline quality natural gas as fuel	Exclusive use of pipeline quality natural gas as fuel

The applicant proposes to meet the following levels if the GE LM6000 CTGs are selected:

Table 5 - Roseville Energy Park Proposed Best Available Control Technology – GE LM6000				
NO_X	CO	VOC	PM_{10}	SO_X
2.0 ppmvd @ 15% O_2, 1-hour rolling average	4 ppmvd @ 15% O_2, 3 –hour average	2 ppmv	Exclusive use of pipeline quality natural gas as fuel	Exclusive use of pipeline quality natural gas as fuel
Water Injection, SCR	Oxidation Catalyst	Good combustion control and oxidation catalyst	Exclusive use of pipeline quality natural gas as fuel	Exclusive use of pipeline quality natural gas as fuel

The District performed a BACT analysis shown in Appendix B. The control equipment and emission limits were determined meet to BACT requirements. Permit conditions will require meeting these limits and demonstrating compliance by performance testing and monitoring.

Natural gas provided by utilities in California should contain no more than 1 grain (g) per 100 standard cubic feet (scf) of total sulfur. This level is considered BACT. The applicant's calculations for SOx are base on 0.5 g/dscf and the applicant bears the responsibility of assuring that natural gas is provided with this low sulfur content.

VII. EMISSIONS

Construction Emissions

Roseville Electric provided an estimate of construction emissions as summarized below:

Table 6 – Construction Emissions*		
Pollutant	Lbs/day	Tons/year
NOx	291.2	18.0
CO	360.7	59.5
VOCs	52.2	7.3
PM-10	20.8	1.35
SOx	23.9	1.0

*Responses to CEC Staff, Data Requests, February 2004, Attachment Air-3, Construction Emission Tables, Table 7

The construction emissions are significant for NOx, CO and VOCs. The PCAPCD recommends the construction mitigation measures shown on page 42. These are standard mitigation measures recommended by PCAPCD for large land use projects and PCAPCD requests these be required unless the Energy Commission determines other conditions typically required for power plants supersede or are otherwise more appropriate in mitigating construction emissions.

Facility Emissions

The air emissions from the facility were calculated based on (1) data from the turbine manufacturers, (2) data from engine manufacturers, (3) proposed BACT emission rates, and (4) hours of operation shown in Table 1 and number of expected cold, warm and hot starts of the combustion turbines.

The applicant resubmitted emissions tables for the gas turbines to the District on April 9, 2004. The revised tables are shown in Appendix C. These were changes to the Alstom GTX100 gas turbine emission rates and revisions to the proposed number of warm starts to be used to calculate emissions from either the GE or Alstom gas turbines.

The PCAPCD has calculated the emissions as shown in the spreadsheets in Appendix D. There are minor differences in the calculated emissions. PCAPCD does accept the applicants revised emissions as representative of the facility emissions with the exception of the NOx emissions from the standby generator. These should be reduced by 4 pounds per quarter to reflect BACT of 6.9 grams per horsepower hour for this engine. The maximum potential air emissions of criteria pollutants from the facility are summarized below.

Gas Turbines

As previously stated, Roseville Electric proposes to install either two Alstom GTX100 gas turbines or two GE LM6000 gas turbines. The emissions from each option are shown in the following tables.

If the Alstom GTX100 turbine are selected the emissions are shown below:

Table 7- Alstom GTX100 Gas Turbines

Pollutant	Lbs/hr Max Two Turbine	Lbs/day Max Two Turbines	Quarter 1 (lbs/quarter) Two turbines	Quarter 2 (lbs/quarter) Two Turbines	Quarter 3 (lbs/quarter) Two turbines	Quarter 4 (lbs/quarter) Two Turbines	Tons/ Year Two Turbines
NOx	74.2	406.0	18,972	18,388	20,185	20,296	38.92
CO	179.0	629.5	26,787	32,590	28,175	29,862	58.71
VOCs	39.4	223.1	5,791	7,306	6,630	6,848	13.29
PM-10	6.4	211.8	16,300	13,692	17,789	17,569	32.67
SOx	1.3	44.0	3,385	2,843	3,694	3,648	6.78

Alternatively, the applicant may select two GE LM6000 turbines and the emissions are shown below.

Table 8 - GE LM6000 Gas Turbines							
Pollutant	Lbs/hr Max Two Turbine	Lbs/day Max Two Turbines	Quarter 1 (lbs/quarter) Two Turbines	Quarter 2 (lbs/quarter) Two Turbines	Quarter 3 (lbs/quarter) Two Turbines	Quarter 4 (lbs/quarter) Two Turbines	Tons/year Two Turbines
NOx	38.7	268.7	17,614	15,491	19,112	18,998	35.61
CO	28.7	300.8	21,291	18,454	23,160	22,982	42.94
VOCs	3.5	83.6	6,006	5,038	6,555	6,473	12.04
PM-10	9.2	221.6	15,968	13,425	17,410	17,199	32.00
SOx	1.9	46.0	3,316	2,788	3,615	3,571	6.65

The maximum hourly emission rates shown are during a cold start of both turbines. The maximum daily emissions were calculated assuming one cold start for 3 hours, one warm start for 1 hour and 19 hours of peak operating with duct burners. Quarterly emissions were calculated as described below:

2 x lbs/hour/turbine @ base load x hours/quarter @ base load +

2 x lbs/hour/turbine @ peak load x hours/quarter @ peak load +

lbs/start/both turbines during cold start x cold starts/quarter +

lbs/start/both turbines during warm start x warm starts/quarter +

lbs/start/both turbines during hot start x hot starts/quarter

The emission rates are shown in the applicant's Tables 3.1-12 and 3.1-14 in Appendix C. The hours per quarter are shown in the following table:

Table 9 - Power Plant Gas Turbine Operating Schedule					
	1st	2nd	3rd	4th	Annual
Base load only hours	1,123	1,188	751	852	3,914
Peaking hours (duct firing)	929	559	1,347	1,246	4,081
Hours of hot starts	25	71	29	42	167
Hours of warm starts	16	40	2	2	60
Hours of cold starts	3	6	3	3	15
Total hours	2,096	1,864	2,132	2,145	8,237

The previous tables addressed criteria pollutants. Other emissions include ammonia which is used to control NOx from the CTGs.

The application indicates that maximum ammonia emissions rates are as follows:

Table 10 – Ammonia Emissions		
	Peak (lbs/hour)	Base (lbs/hour)
GE LM6000	9.2	6.3
Alstom GTX100	9.5	6.4

The PCAPCD Rules and Regulations do not set standards for ammonia emissions. Ammonia is a concern because it is a hazardous air pollutant and also because of the potential formation of secondary particulate matter.

The applicant has included ammonia in the risk assessment for the facility. The applicant proposes to limit ammonia slip to 10 ppmv. This will be a condition of the permit.

Auxiliary Equipment

Auxiliary Boiler

The emissions from the auxiliary boiler were manufacturer's data based on CO emissions of 50 ppmv @ 3% O2 and NOx emissions of 9 ppmv @3% O2.

Table 11 – Boiler							
Pollutant	Lbs/hr Max	Lbs/day Max	Quarter 1 (lbs/quarter)	Quarter 2 (lbs/quarter)	Quarter 3 (lbs/quarter)	Quarter 4 (lbs/quarter)	Tons/ year
NOx	0.7	16.8	92	372	94	94	0.33
CO	2.2	52.8	311	1,259	317	317	1.10
VOCs	0.3	7.2	36	144	36	36	0.13
PM-10	0.6	14.4	82	332	84	84	0.29
SOx	0.08	1.92	11	46	12	12	0.04

The maximum daily emissions assume 24 hours of operation. The quarterly emissions were based on maximum hourly emissions multiplied by the number of hours per quarter proposed by the applicant. The hours are shown in the following table:

Table 12 – Boiler Operating Schedule (Hours)					
	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual
Auxiliary Boiler	140	568	143	143	995

Cooling Tower

Table 13 - Cooling Towers							
Pollutant	Lbs/hr Max	Lbs/day Max	Quarter 1 (lbs/quarter)	Quarter 2 (lbs/quarter)	Quarter 3 (lbs/quarter)	Quarter 4 (lbs/quarter)	Tons/year
PM-10	0.68	16.3	1,471	1,487	1,504	1,504	3.0

PM10 emission rates were calculated follows:

> PM10 = cooling water recirculation rate x total dissolved solids concentration in the blowdown water x design drift rate.

Emergency Generator

Table 14 – Emergency Generator – 1,133 Hp Diesel Engine							
Pollutant	Lbs/hr Max	Lbs/day Max	Quarter 1 (lbs/quarter)	Quarter 2 (lbs/quarter)	Quarter 3 (lbs/quarter)	Quarter 4 (lbs/quarter)	Tons/ year
NOx	4.31	4.31	108	108	108	108	0.22
CO	0.84	0.84	21	21	21	21	0.04
VOCs	0.16	0.16	4	4	4	4	0.008
PM-10	0.14	0.14	3	3	3	3	0.007
SOx	0.10	0.10	2	2	2	2	0.005

The emergency generator engine calculations assume half load and operations of up to 50 hours per year (or 12.5 hours per quarter).

Emergency Fire Pump

Table 15 – Emergency Fire Pump – 300 hp Diesel Engine							
Pollutant	Lbs/hr Max	Lbs/day Max	Quarter 1 (lbs/quarter)	Quarter 2 (lbs/quarter)	Quarter 3 (lbs/quarter)	Quarter 4 (lbs/quarter)	Tons/ year
NOx	1.72	1.72	43	43	43	43	0.086
CO	0.09	0.09	2	2	2	2	0.005
VOCs	0.05	0.05	1	1	1	1	0.002
PM-10	0.03	0.03	1	1	1	1	0.002
SOx	0.19	0.19	1	1	1	1	0.002

The fire pump engine calculations assume half load and operations of up to 50 hours per year (or 12.5 hours per quarter). In summary, the facility emissions are shown in the following tables for each turbine option:

Table 16 - ALSTOM GX100 - FACILITY QUARTERLY EMISSION LIMITS					
POLLUTANT	QUARTER 1 (lbs)	QUARTER 2 (lbs)	QUARTER 3 (lbs)	QUARTER 4 (lbs)	Tons/year
NO_x	19,215	18,911	20,429	20,541	39.55
CO	27,121	33,872	28,515	30,202	59.86
VOC	5,832	7,455	6,672	6,890	13.42
PM_{10}	17,854	15,513	19,378	19,158	35.95
SO_2	3,400	2,893	3,709	3,663	6.83

Table 17 – GE LM6000 - FACILITY QUARTERLY EMISSION LIMITS					
POLLUTANT	QUARTER 1 (lbs)	QUARTER 2 (lbs)	QUARTER 3 (lbs)	QUARTER 4 (lbs)	Tons/year
NO_x	17,857	16,015	19,357	19,243	36.24
CO	21,625	19,737	23,500	23,322	44.09
VOC	6,046	5,188	6,596	6,514	12.17
PM_{10}	17,523	15,246	18,999	18,788	35.28
SO_2	3,331	2,838	3,630	3,587	6.69

VIII. OFFSETS

PCAPCD rules require offsets for emission increases for regulated air pollutants which exceed the trigger levels shown in Rule 502, New Source Review, Section 302, Offset Requirements General. These trigger levels are 7,500 pounds per quarter for NOx, CO, PM-10 and VOCs and 12,500 pounds per quarter for SOx. Offsets for CO are not required if the applicant demonstrates by modeling that CO emissions will not cause an increase in ambient concentrations CO of more than 500 micrograms per cubic meter on an eight hour average at or beyond the property line.

The following tables compare the facility emissions to the offset trigger levels.

If the Alstom GX100 turbines are selected for the project, the facility quarterly potential to emit and offset trigger levels are shown in the following table:

Table 18 - ALSTOM GX100 - FACILITY QUARTERLY OFFSETS						
POLLUTANT	QUARTER 1 (lbs)	QUARTER 2 (lbs)	QUARTER 3 (lbs)	QUARTER 4 (lbs)	Trigger Level (lbs per quarter)	Offsets Required
NO_x	19,215	18,911	20,429	20,541	7,500	Yes
CO	27,121	33,872	28,515	30,202	7,500 or modeling	No
VOC	5,832	7,455	6,672	6,890	7,500	No
PM_{10}	17,854	15,513	19,378	19,158	7,500	Yes
SO_2	3,400	2,893	3,709	3,663	12,500	No

The modeling using ISCST3 has shown that maximum CO impacts during operation are 134 micrograms per cubic meter. Offsets for CO will not be required because the increase in ambient CO concentrations will not exceed more than 500 micrograms per cubic meter on an eight hour average at or beyond the property line.

The maximum CO impacts during commissioning are 603.2 micrograms, eight-hour average. The modeling was based on a maximum of 1000 pounds per hour of CO. CO emissions and ambient impacts are much higher during commissioning because the oxidation catalyst is not in place to control the emissions.

This equals 8000 pounds in an eight hour period. In order to prevent CO impacts of more than 500 micrograms per cubic meter, the CO emissions during commissioning operations must be limited to no more than 500/603.2 X 1000 pounds or 829 pounds per hour. This will be a condition of the permit. Once the turbine commissioning phase is completed, the use of the CO oxidation catalyst will limit the concentration of CO to well below the offset 500 microgram per cubic meter level.

Offsets are not required for SOx and VOC emissions because they are below the required trigger levels.

If the Alstom GX100 turbines are selected, emission offsets are required for NOx and PM-10 in the quantities shown in the following table.

Table 19 – ALSTOM GX100 - OFFSETS REQUIRED					
POLLUTANT	QUARTER 1 (lbs/quarter)	QUARTER 2 (lbs/quarter)	QUARTER 3 (lbs/quarter)	QUARTER 4 (lbs/quarter)	Tons/year
NOx	19,215	18,911	20,429	20,541	39.55
PM-10	17,854	15,513	19,378	19,158	35.95

NOx and VOC emission reductions that occurred during calendar quarter 2, beginning April 1, and calendar quarter 3, beginning July, 1 may be used to offset increases in NOx and VOC occurring during any quarter of the year.

<u>GE LM6000 - Quantity of Offsets Required</u>

If the GE LM6000 turbines are selected for the project, the facility potential to emit and offset trigger levels are shown in the table below:

Table 20 - GE LM6000 – FACILITY QUARTERLY EMISSION LIMITS						
POLLUTANT	**QUARTER 1 (lbs)**	**QUARTER 2 (lbs)**	**QUARTER 3 (lbs)**	**QUARTER 4 (lbs)**	**Trigger Level (lbs per quarter)**	**Offsets Required**
NO_x	17,857	16,015	19,357	19,243	7,500	Yes
CO	21,625	19,737	23,500	23,322	7,500 or modeling	No
VOC	6,046	5,188	6,596	6,514	7,500	No
PM_{10}	17,523	15,246	18,999	18,788	7,500	Yes
SO_2	3,331	2,838	3,630	3,587	12,500	No

Offsets for CO are not required. The air modeling for CO emissions demonstrated that the plant would not cause an increase in ambient concentrations of CO of more than 500 micrograms per cubic meter on an eight hour average at or beyond the property line.

Offsets are not required for SOx and VOC emissions because they are below the required trigger levels.

If the GE LM-6000 turbines are selected, emission offsets are required for NOx and PM-10 in the quantities shown in the following table.

Table 21 – GE LM6000 - OFFSETS REQUIRED					
POLLUTANT	QUARTER 1 (lbs/quarter)	QUARTER 2 (lbs/quarter)	QUARTER 3 (lbs/quarter)	QUARTER 4 (lbs/quarter)	Tons/year
NOx	17,857	16,015	19,357	19,243	36.24
PM-10	17,523	15,246	18,999	18,788	35.28

NOx and VOC emission reductions that occurred during calendar quarter 2, beginning April 1, and calendar quarter 3, beginning July, 1 may be used to offset increases in NOx and VOC occurring during any quarter of the year.

Proposed offsets

In the AFC, Roseville Electric submitted a listing all available ERCs in the Sacramento region. A confidential listing was submitted separately to the PCAPCD indicating those parties with whom they were negotiating for the purchase of the ERCs.

Enron North America ERCs

Roseville Electric released a public letter dated 2/25/04 which indicated a purchase and sale agreement had been executed for the following ERCs which are currently owned by Enron North America.

Table 22 - ERCs Covered by Purchase and Sale Agreement		
PCAPCD Certificate No.	Pollutant	Quantity (tons/year)
2001-22	PM-10	28.4
2001-23	NOx	10.1
2001-26	VOC	67.0
2001-24	PM-10	29.4

PCAPCD ERC Certificate 2001-22

PM-10 emission reductions were issued in ERC Certificate 2001-20 for the 1996 shutdown of the aggregate handling facility located at 1800 Sunset Blvd. In Rocklin, CA operated by R.C. Collet. The equipment included number grizzlies, screens, crushers, stackers and conveyors. All aggregate operations were shutdown at that time.

The historical emissions from the operations were calculated using AP-42, Fourth Edition. Emissions from these operations were controlled by water sprays on transfer points and watering of unpaved roads. The control efficiency of the water sprays were considered in the calculation of the ERCs to be 90%. Additional RACT or BARCT for PM-10 was not identified at the time the ERCs were issued.

This certificate was purchased by Enron North America and reissued as ERC Certificate 2001-22. The quantities are shown below:

TABLE 23 – ERC Certificate 2001-22					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
PM-10	2,578	22,263	16,085	15,916	28.4

The reductions occurred approximately 7 miles from the location of the REP. The location is in the District and in the Sacramento Valley Air Basin. These ERCs will require an offset ratio adjustment of 1.3.

PCAPCD ERC Certificate 2001-23

NOx emission reductions were originally issued in ERC Certificate 2001-02 for the 1993 shutdown of the two wood-fired boilers at the Georgia Pacific lumber mill at 23801 Foresthill Road, Foresthill, CA. All operations were shutdown at that time.

NOx emissions were calculated from a source test and averaged over two years. The NOx emissions were RACT/BARCT adjusted to the equivalent 0.052 lbs/MMbtu. The NOx were further reduced by 5% for the District Priority Reserve. No other additional RACT/BARCT adjustments are required.

This certificate was purchased by Enron North America and reissued as ERC Certificate 2001-23. The quantities are shown below:

TABLE 24 – ERC Certificate 2001-23					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
NOx	5,050	5,050	5,050	5,050	10.1

The reductions occurred approximately 25 miles from the location of the REP. The location is in the Mountain County Air Basin. These ERCs will require an offset ratio adjustment of 2.0.

PCAPCD ERC Certificate 2001-24

PM-10 emission reductions were issued in ERC Certificate 2001-03 for the 1993 shutdown of the two wood-fired boilers and the sawmill at the Georgia Pacific lumber mill at 23801 Foresthill Road, Foresthill, CA. All operations were shutdown at that time.

Roseville Electric has an agreement to purchase up to 29.4 tons per year of PM-10 from this certificate. Emissions from the two boilers were calculated from a source test and averaged over two years. The PM-10 emissions were controlled by a large cyclone. The cyclone was considered RACT/BARCT. PM-10 emissions were not RACT/BARCT adjusted. The emissions from the sawmill were calculated from AP-42 emission factors and production records. Additional RACT or BARCT for PM-10 from the sawmill was not identified at the time the ERCs were issued. The PM-10 emissions were reduced by 5% for the District Priority Reserve. No other RACT/BARCT adjustments are required.

This certificate was purchased by Enron North America and reissued as ERC Certificate 2001-24. The quantities issued were 50,676 pounds per quarter for each quarter or 101.3 tons. Roseville Electric proposes to use 29.4 tons of these to offset PM-10 emissions. If split evenly across all quarters the amount would be:

TABLE 25 – ERC Certificate 2001-24					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
PM-10	14,700	14,700	14,700	14,700	29.4

The reductions occurred approximately 25 miles from the location of the REP. The location is in the Mountain County Air Basin. These ERCs will require an offset ratio adjustment of 2.0.

PCAPCD ERC Certificate 2001-26

VOC emission reductions credits were issued in ERC Certificate 2001-05 for the 1993 shutdown of the two wood-fired boilers at the Georgia Pacific lumber mill at 23801 Foresthill Road, Foresthill, CA. All operations were shutdown at that time.

VOC emissions were calculated from a source test and averaged over two years. The VOC emissions were not RACT/BARCT adjusted. RACT or BARCT for VOCs was not identified at the time the ERCs were issued. The VOC emissions were reduced by 5% for the District Priority Reserve. No other additional RACT/BARCT adjustments are required.

This certificate was purchased by Enron North America and reissued as ERC Certificate 2001-26. The quantities are shown below:

TABLE 26 – ERC Certificate 2001-26					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
VOCs	33,512	33,512	33,512	33,512	67.0

Roseville Electric proposes to use these offsets for an interpollutant trade of VOCs for NOx.

The reductions occurred approximately 25 miles from the location of the REP. The location is in the Mountain County Air Basin. These ERCs will require an offset ratio adjustment of 2.0.

CALPINE CORPORATION ERCs

Roseville Electric released a letter on May 4, 2004 indicating they have completed negotiations with Calpine Corporation for the purchase of 12.37 tons of NOx ERCs. These were issued in two certificates EC-209 and EC-210 by the Yolo-Solano Air Quality Management District (YSAQMD).

YSAQMD EC-209

The District has reviewed the documents on these ERCs provided by YSAQMD. The original ERC Certificate EC-8393-94-01 was issued for the shutdown of the beet pulp process at the former Delta Sugar Plant located at the intersection of River Road and Willowpoint Road in Clarksburg. The equipment included one 120 MMBtu/hr dryer (also called a dehydrator) dual fired on natural gas and woodwaste and five (5) 174 hp, natural gas fired rich burn engines. The amount of NOx ERCs issued initially were 903 pounds in Quarter 1, 74,926 pounds in Quarter 2, 23,928 pounds in Quarter 3 and 31,141 pounds in Quarter 4.
ARB provided written comments suggesting that the emissions from the engines were not BARCT adjusted as required by YSAQMD Rule 3.14. Subsequently YSAQMD issued the ERC Certificate with an advisory that these emission reduction credits may be subjected to an adjustment as required by Federal, State and District policies and regulations at the time of use.

The BARCT adjustment was made at the time a portion of the ERCs in Certificate EC-8393-94-01 were transferred to Calpine Corporation in April, 1999. The NOx reductions attributed to the five engines were adjusted from an emission level of 1235 ppmv @15% O2 to 25 ppmv @ 15% O2. After this adjustment, Certificate EC-0060 was issued for NOx in the amount of 328 pounds in Quarter 1, and 27,237 pounds in Quarter 2, and 8,698 pounds in Quarter 3 and 11,320 pounds in Quarter 4.

Certificate EC-0060 was split into two certificates so that Calpine Corporation could surrender a portion of the ERCs to the Feather River AQMD. The balance of the NOx ERCs were issued in Certificate EC-209 for the amount of 20,588 pounds in Quarter 2, and 3,542 pounds in Quarter 4.

The NOx ERCs in EC-209 have been reissued in Certificate EC-238 for the same amounts of 20,588 pounds in quarter 2 and 3,542 in quarter 4. The new certificate was issued because of a transfer of VOC ERCs from Calpine Corporation to Leer West.

Roseville Electric is proposing to utilize the following quantities from a portion of EC-238:

TABLE 27 – YSAQMD Certificate EC-238 (From EC-209)					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
NOx	0	6,888	0	3,542	5.22

The reductions occurred approximately 35 miles from the location of the REP. The location is outside of the PCAPD and in the Sacramento Valley Air Basin. These ERCs will require an offset ratio adjustment of 2.1.

YSAQMD EC-210

Emission reduction credits for NOx were originally issued in ERC Certificate EC-8693-94-01 by YSAQMD for the 1993 shutdown of lime kiln operation at the Delta Sugar Plant located at the intersection of River Road and Willowpoint Road in Clarksburg, CA.

The calculations utilized the average tons of coke burned in the lime kiln and AP-42 emission factors to calculate NOx and other emissions. A RACT adjustment was not applied to the emissions.

The original certificate was issue for the following amounts of NOx: Quarter 1: 128 lbs, Quarter 2: 10,620 lbs, Quarter 3: 3,392 lbs and Quarter 4: 4,414 lbs. The ERCs for the 1st and 3rd quarter were surrendered to the Feather River AQMD for Calpine's Sutter Project. The balance was reissued to Calpine Corporation in Certificate EC-210 for the amounts shown below:

TABLE 28 – YSAQMD Certificate EC-210					
Pollutant	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
NOx	0	10,620	0	4,414	7.52

The reductions occurred approximately 35 miles from the location of the REP. The location is outside of the PCAPD and in the Sacramento Valley Air Basin. These ERCs will require an offset ratio adjustment of 2.1.

The following tables summarizes the ERCs currently identified by Roseville Electric and which have been released from identification as Confidential:

Table 29 - Emission Reduction Credits Certificates						
NOx	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-23	5,050	5,050	5,050	5,050	10.1
Calpine Corp.	YSAQMD/ EC-209 (EC-238)	0	6,888	0	3,542	5.22
Calpine Corp.	YSAQMD/ EC-210	0	10,620	0	4,414	7.52
NOx	Totals	5,050	22,558	5,050	13,006	22.8
VOCs for NOx	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-26	33,512	33,512	33,512	33,512	67.0
VOCs for NOx	**TOTALS**	33,512	33,512	33,512	33,512	67.0
PM-10	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-24	14,700	14,700	14,700	14,700	29.4
Enron North America	PCAPCD/ 2001-22	2,578	22,263	16,085	15,916	28.4
PM-10	**TOTALS**	17,278	36,963	30,785	30,616	57.8

These ERCs need to be adjusted by the offset ratios shown in the following table from PCAPCD Rule 502, New Source Review (8/09/01) with the exception of the ratio for non-attainment pollutants within a 15 mile radius and within the District. The U.S. EPA requires a minimum offset ratio of 1.3 for non-attainment pollutants in an area designated severe ozone non-attainment.

Table 30 – Offset Ratios	
Location of Offset	NOx and PM-10
Within 15-Mile Radius and within the District	1.3 to 1.0
Within 15-Mile Radius, outside the District, but within the same air basin	1.3 to 1.0
Greater than 15-Mile but within	2.0 to 1.0

50-Mile Radius and within District	
Greater than 15-Mile but within 50-Mile Radius and outside the District, but within the same air basin	2.1 to 1.0
More than 50-Mile Radius and within the same air basin	2.2 to 1.0

Table 31 – ERCs Adjusted for Offset Ratios							
NOx	District/ Certificate #	Offset Ratio	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-23	2.0	2,525	2,525	2,525	2,525	**5.1**
Calpine Corp.	YSAQMD / EC-209 (EC-238)	2.1	0	3,280	0	1,687	**2.5**
Calpine Corp.	YSAQMD / EC-210	2.1	0	5,057	0	2,102	**3.6**
NOx	Totals		2,525	10,862	2,525	6,314	**11.1**
VOCs for NOx*	District/ Certificate #						
Enron North America	PCAPCD/ 2001-26	2.0	16,756	16,756	16,756	16,756	**33.5**
VOCs for NOx	**TOTALS**		16,756	16,756	16,756	16,756	**33.5**
PM-10	District/ Certificate #						
Enron North America	PCAPCD/ 2001-24	2.0	7,350	7,350	7,350	7,350	**14.7**
Enron North America	PCAPCD/ 2001-22	1.3	1,983	17,125	12,373	12,243	**21.9**
PM-10	**TOTALS**		9,333	24,475	19,723	19,593	**36.6**

*Roseville Electric has proposed to use interpollutant trading to offset NOx increases with VOC ERCs. The proposed interpollutant trading ratio is 2.6. See discussion of interpollutant trading ratio. These credits must be further adjusted.

A review of these certificates indicated the necessary offsets for PM-10 are available. Additional ERCs to offset the NOx emissions are required. Roseville Electric proposes to provide additional NOx ERCs and use interpollutant trading of VOC to NOx to fulfill the remainder of the NOx offset requirements.

On February 23, 2004, Roseville Electric filed a confidential air quality ERC table which identified the air district, owner, distance from Roseville Energy Park and quantities of ERCs tons per year. The table does not identify the specific ERCs certificates under consideration. Roseville Electric has not yet removed the "confidential" designation from their proposed February 23rd ERC table. These ERCs will be discussed generally in the following paragraph.

The confidential ERC table identified VOC and NOx ERCs from the northern portion of the Sacramento Valley but outside the Sacramento Federal Ozone Non-attainment Area for Ozone that is designated Severe by the U.S. EPA. The northern portion of the Sacramento Valley is designated Moderate. Rule 502, New Source Review, Offset General, Section 302.6, states that offsets can only come from regions with the same air quality designations or worse designations than that of the emissions unit or stationary source requiring the offsets. VOC and NOx ERCs may not be obtained from the northern portion of the Sacramento Valley. They may only be obtained from Placer County (excluding Lake Tahoe), El Dorado (excluding Lake Tahoe), South Sutter County, Sacramento County, Yolo County and a portion of Solano County. Roseville Electric was made aware of this issue and verbally indicated these NOx and VOC ERCs from outside the Sacramento Federal Ozone Non-attainment Area will not be used to offset this project.

PM-10 ERCs are also listed from the northern portion of the Sacramento Valley. This area has the same attainment designation for PM-10. All are designated as attainment for federal standards and non-attainment for state standards. PM-10 ERCs are allowed from this area with an offset ratio of 2.1 or greater. ERCs to offset PM-10 from the northern portion of the Sacramento Valley are not expected because sufficient PM-10 ERCs have been identified from Placer County.

Roseville Electric is proposing to complete the offset package with additional NOx ERCs and by using an interpollutant trade of VOCs for NOx ERCs from both Placer County and the surrounding Sacramento Federal Ozone Non-Attainment Area. Interpollutant trading will be discussed later in this document.

Additional NOx ERCs

Roseville Electric has indicated they are negotiating to obtain the necessary additional NOx ERCs. They have also proposed creating ERCs in Placer County from two sources. These are Energy 2001 and Union Pacific Railyard. Both are located in or near Roseville.

The Union Pacific Railyard spans both Sacramento County and Placer County. The majority of the emissions are from locomotives moving through and stopping in the yard, from locomotive switchers which stay in the yard to move railcars and from a maintenance shop which tests locomotives. The emissions from these activities are currently not regulated.

Roseville Electric has been working with Union Pacific to develop a program to retrofit four (4) of the locomotive switchers with retrofit kits developed by General Electric. They have indicated there is a potential emission reduction of 42 tons of NOx per year.

The PCAPCD does not require permits for these operations at the railyard. They are regulated under federal law. PCAPCD believes the development of such a program to create ERCs may be feasible. However, the extensive amount of work to develop a protocol, complete rule development, have the rule considered by the District Board, establish that ERCs are real, quantifiable, surplus and federally enforceable cannot be realistically completed in the near term. There is no assurance at this time that these potential emission reductions will actually occur or can be certified as ERCs.

The other source from which Roseville Electric has proposed creating ERCs is Energy 2001. This facility is located at the Western Regional Landfill near Roseville. Energy 2001 has a permit to operate a landfill gas engine. Energy 2001 has recently obtained an Authority to Construct to replace the one engine with two engines. Roseville Electric is proposing to install additional control equipment to reduce NOx emissions and obtain NOx ERCs.

The PCAPCD has notified Roseville Electric that this facility has not operated recently and does not have historical actual emissions. There is no assurance that emission reductions will occur in the future or that they can be certified as ERCs.

Interpollutant Offsets

An interpollutant offset is the use of ERCs of one pollutant to offset the increase in emissions of another pollutant. PCAPCD Rule 502, New Source Review, Section 304, allows the PCAPCD Air Pollution Control Officer to approve interpollutant offsets for precursor pollutants.

304 INTERPOLLUTANT OFFSETS: The Air Pollution Control Officer may approve interpollutant offsets for precursor pollutants on a case by case basis, provided that the applicant demonstrates through the use of an air quality model 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 Air Pollution Control Officer shall impose, based on an air quality analysis, offset ratios greater than the requirements of Section 303. Interpollutant offsets between PM10 and PM10 precursors may be allowed only if PM10 precursors contribute significantly to the PM10 levels that exceed the PM10 ambient standards. PM10 emissions shall not be allowed to offset nitrogen oxides or reactive organic compound emissions in ozone nonattainment areas, nor be allowed to offset sulfur oxide emissions in sulfate nonattainment areas.

PCAPCD has reviewed interpollutant offsets ratios used for power plants in other districts in California. The following VOC for NOx interpollutant offsets were identified:

Table 32
Interpollutant Trade Ratios Used for Power Plants in Other Districts

District	Project	VOCs for NOx Ratio
Bay Area Air Quality Management District	Delta Energy	1:1
Mojave Air Quality Management District	High Desert	1.6:1
Monterey Air Quality Management District	Moss Landing	1:1
Mojave Air Quality Management District	Blythe	1.6:1
Bay Area Air Quality Management District	Metcalf	1:1
San Louis Obispo Air Pollution Control District	Morro Bay	1:1
South Coast Air Quality Management District	Mountainview	1:1
San Diego Air Quality Management District	Otay Mesa	2:1
Bay Area Air Quality Management District	Valero	1:1
Sacramento Municipal Air Quality Management District	Consumnes Power Plant Project	2.6:1

Although not shown in the table, SMUD has utilized a 2.0 interpollutant trading for other projects in the Sacramento area.

The ARB Guidance for Power Plant Siting and Best Available Control Technology (7-22-99) was reviewed in considering the proposed interpollutant trading ratio. Page 10, Table I-3, Minimum Interpollutant Offset Ratios, recommended the minimum ratio should be basin specific and no less than 1.0:1. Page 11, Table I-4, Minimum Interbasin Offset Ratios, indicate the minimum offset ratio for offsets within 50 miles should be 2.0 to 1.

Interpollutant offsets were not discussed in the application for the REP. During later discussions concerning offsets, Roseville Electric has proposed the use of interpollutant offsets of VOCs for NOx. VOCs and NOx are considered precursors to ozone formation. This may be allowed under Section 304 provided the applicant demonstrates through the use of an air quality model that the emission increase from the new or modified source will not contribute to a violation of an ambient air quality standard.

Roseville Electric's proposal for determining an interpollutant trading ratio is shown in Appendix E. Roseville Electric has proposed to establish the interpollutant offset ratio by utilizing the modeling and analysis performed for the Sacramento Municipal Utility District (SMUD) Consumnes River Project which was approved by the Energy Commission in 2003.

Roseville Electric provided the Sacramento Metropolitan Air Quality Management District (SMAQMD) Final Determination of Compliance, Consumnes Power Plant (October 21, 2002) to the PCAPCD for reference. Appendix B-1 of the Consumnes Power Plant PDOC, VOC for NOx Interpollutant Trade Analysis, describes the analysis performed for this power plant.

The Consumnes Power Plant (CPP) project consists of four combined cycle gas turbines with a nominal output of 1,060 megawatts. The project will be built in two phases. Offsets have been provided for the first phase. These offsets included interpollutant trading of VOC for NOx and SOx for PM-10. The Consumnes Power Plant project is on a site approximately ½ mile south of the Rancho Seco Nuclear Power Plant which is being decommissioned. It is located in Township 6N, Range 9E, Section 29 in the Sacramento Valley Air Basin approximately 25 miles southeast of the City of Sacramento in Sacramento County and 35 miles south of the Roseville Energy Park. The Consumnes project elevation is 160 feet above sea level.

A number of interpollutant analysies were performed for the CPP. These included (1) Urban Airshed Modeling (UAM) by Systems Application International (SAI), (2) Federal Implementation Plan (FIP) Diagram based on EPA UAM Results, (3) State Implementation Plan (SIP) UAM EKMA Diagram from 1994 SIP, (4) Extent of Reaction Analysis (Charles Blanchard's), (5) Ambient NOx, NMHC and Ozone Relationships (Sierra Research Analysis) and (6) SIP UAM Modeling Performance Evaluation (ARB) and PAMS data analysis (SMAQMD).

These analysies showed a variety of indications of interpollutant ratios, ranging from 0.2 to 1 to 50 to 1.

Ultimately the interpollutant ratio for the CPP was based on the average of the SAI UAM results shown in the following from page 118 of the SMAQMD FDOC.

Table 33 - Consumnes Power Plant, VOC to NOx Ratios, SAI UAM						
Measure	July 12			July 13		
1-hr ozone peak	---	---	1	---	---	1.0
Max change in 1-hr ozone	1.0	1.2	1.9	1.7	2.0	1.4
8-hr ozone peak	---	---	---	---	---	1.0
Max. change in 1-hr ozone	3.2	1.4	2.3	7.9	2.3	1.4
VOC to NOx Ratio Average = 2.0						

The final interpollutant ratio was increased by 30% to take into account uncertainties in the modeling and other analysis. The interpollutant trading ratio was set at 2.0 + 2.0 *0.30 or 2.6. SMAQMD also applied an offset ratio of 1.3 resulting in an overall VOC for NOx ratio of 3.9 to 1.

Roseville Electric is proposing to use the determined interpollutant trading ratio of 2.6 to 1. The PCAPCD offset ratio of 2.0 to 1 for offsets generated more than 15 miles but within a 50 mile radius will apply to most of the VOC for NOx interpollutant trading. The resulting overall VOC for NOx ratio will be 5.2.

District staff discussed this issue with Mr. Mark Sims, Environmental Engineer, U.S. EPA Region IX. Mr. Sims indicated that USEPA modeling staff had looked at the modeling performed by SMUD for the CPP. He stated that EPA required, at a minimum, that with the Urban Airshed Model will be required to determine the appropriate interpollutant trading ratio.

The PCAPCD concludes that the proposed interpollutant trading ratio of 2.6 to 1 is equal to or higher than those found on other projects and the resulting overall ratio of 5.2 is considerably higher than used on other projects. In summary, additional modeling is required to make a final determination of the appropriate interpollutant trading ratio unless EPA concurs that the 5.2 ratio is acceptable.

IX. AIR MODELING

Modeling was performed by the applicant to analyze the impacts of the project on ambient air quality using an approved regulatory modeling program, Industrial Source Complex Short Term, ISCST3. The emission rates used as input in the modeling were based on the worst case or highest emissions for each pollutant for each of two turbine manufacturers.

The turbine emissions were revised and resubmitted to the District on April 9, 2004. The new emissions estimates were revised downward with the most significant change being reduced CO and VOC emission rates from the Alstom turbines. Emissions were not revised for the GE CTGs. Modeling has not been resubmitted as the revised emissions would produce impacts that are less than those listed in the following tables. The current modeling used the prior higher emission estimates for the Alstom CTGs and can be used conservatively to estimate the maximum impacts.

TABLE 34 - GE LM600 MODELING RESULTS COMPARED TO CAAQS AND NAAQS						
Pollutant	**Averaging Period**	**Background Concentration ($\mu g/m^3$)**	**ISCST3 Modeled Impact ($\mu g/m^3$)**	**Predicted Total Concentration ($\mu g/m^3$)**	**CAAQS ($\mu g/m^3$)**	**NAAQS ($\mu g/m^3$)**
NO_2	1-hour	161.8	275.76	437.56	470	-
	Annual	32.0	0.99	32.99	-	100
CO	1-hour	5269.8	377.12	5,46.92	23,000	40,000
	8-hour	3551.4	126.06	3,677.46	10,000	10,000
PM_{10}	24-hour	93.0	16.68	109.68	50	150
	Annual	25.0	0.48	25.48	20	50
SO_2	1-hour	49.8	49.88	99.68	650	-
	3-hour	31.4	9.30	40.70	-	1300
	24-hour	28.8	2.33	31.13	109	365
	Annual	5.2	0.733	5.93	-	80

TABLE 35 - ALSTOM GTX100 MODELING RESULTS COMPARED TO CAAQS AND NAAQS						
Pollutant	**Averaging Period**	**Background Concentration ($\mu g/m^3$)**	**ISCST3 Modeled Impact ($\mu g/m^3$)**	**Predicted Total Concentration ($\mu g/m^3$)**	**CAAQS ($\mu g/m^3$)**	**NAAQS ($\mu g/m^3$)**
NO_2	1-hour	161.8	275.77	437.57	470	-
	Annual	32.0	1.00	33.00	-	100
CO	1-hour	5269.8	377.12	5646.92	23,000	40,000
	8-hour	3551.4	134.13	3685.53	10,000	10,000
PM_{10}	24-hour	93.0	16.68	109.68	50	150
	Annual	25.0	0.48	25.48	20	50
SO_2	1-hour	49.8	49.88	99.68	650	-
	3-hour	31.4	9.3	40.70	-	1300
	24-hour	28.8	2.33	31.13	109	365
	Annual	5.2	0.73	5.93	-	80

The modeling indicates that the project would not cause an exceedence of federal National Ambient Air Quality Standards (NAAQS) for NO_2, CO, PM-10 and SO_2. The modeling indicates that the project would not cause an exceedence of state California Ambient Air Quality Standards (CAAQS) for NO_2, CO, and SO_2.

Placer County is currently designated non-attainment for PM-10 for state standards. The results of modeling PM-10 impacts indicate a maximum impact of 16.68 $\mu g/m^3$ (24-hour) and 0.48 $\mu g/m^3$ (annual). While the facility may not cause additional violations, these impacts are significant because the area is currently exceeding state standards for PM-10 and the impact is approximately 33% of the state standard.

CARB has adopted an annual standard of 12 μg/m^3 for fine particulates less than 2.5 microns (PM-2.5). The PM-10 emissions are from combustion sources. These are believed to be primarily fine particulates less than 2.5 microns. Using the modeling for PM-10, PCAPCD concludes that the estimated PM-2.5 impacts are 0.48 μg/m^3. Background concentrations have not yet been determined.

XII. HEALTH RISK ASSESSMENT

A health risk assessment was performed by the applicant for the proposed project. The results are summarized in the following table:

Table 36
HEALTH RISK ASSESSMENT SUMMARY

Maximum Excess Cancer Risk	0.0743 per million
Acute Inhalation Hazard Index	0.478
Chronic Inhalation Hazard Index	0.011

<u>Excess Cancer Risk</u>

The CARB Risk Management Guidelines for New and Modified Sources of Toxic Air Pollutants (7/93) recommends that districts use an excess cancer risk of 1 per million as the point at which Toxic Best Available Control Technology (T-BACT) is required. They further suggest 10 in a million as the upper level cancer risk for discretionary permitting decisions and a value of 100 in a million as the upper level for all permitting decisions.

The increased cancer risk does not exceed one in one million. The acute and chronic hazard indexes do not exceed 1. A health index of 1 is the maximum a source should be allowed to contribute to the existing health risk. The indices are less than one.

<u>Hazard Index</u>

The estimate of non-cancer health affects is expressed as the ratio of estimated ambient concentration of a substance to the acceptable exposure level. This ratio is called the Hazard Index. The acute hazard index relates to short term exposure. The chronic hazard index relates to long term exposure.

The CARB document suggests setting a total hazard index value of 1 as the upper limit for non-discretionary permitting decisions and 10 as the maximum for all permitting decisions.

The health risk assessment performed indicates a hazard index of less than one which is acceptable under these guidelines.

XI. COMPLIANCE WITH DISTRICT RULES AND REGULATIONS

The PCAPCDs review determined the following Rule and Regulations were applicable to the project and are considered in this evaluation of this project.

RULE 102 DEFINITIONS

Rule 102, Definitions, contains the definitions of terms used in the Placer County APCD Rules and Regulations. For example, included are the definitions of volatile organic compounds and exempt compounds (exempt from the definition of VOC) and standard conditions (60 degrees Fahrenheit and 14.7 pounds per square inch absolute). These definitions apply unless other specific definitions are contained in the individual rules.

RULE 202 VISIBLE EMISSIONS

Rule 202, Visible Emissions, prohibits discharge of an air contaminant from any single source for a period or period aggregating more than three (3) minutes in any hour which is as dark or darker than No. 1 on the Ringlemann or the equivalent opacity (20%). Aggregating means the periods of the exceedences are added during the hour to determine compliance.

The exclusive use of natural gas as fuel for the CTGs is expected to minimize visible emissions. Visible emissions, excluding uncombined water vapor, are not expected to exceed Ringlemann No. 1. The cooling towers are not expected to have visible emissions, excluding uncombined water vapor, greater than 20% opacity.

The emergency generator and the fire pump are driven by diesel engines. Diesels may smoke when first started if the engine is cold. However, a properly maintained diesel engine will not cause visible emissions greater than Ringlemann No. 1 for more than (3) minutes in any one hour.

Compliance is expected.

RULE 204 WET PLUMES

When uncombined water is the only reason for failure to meet the requirements of Rule 202, Visible Emissions, the limitations of Rule 202 do not apply. This rule applies the cooling towers.

Compliance with this rule is expected.

RULE 205 NUISANCE

Rule 205, Nuisance, prohibits the discharge of air contaminants which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public, or which endanger the health and safety of those persons or the public.

Proper operation of the equipment with air pollution controls is not expected to create a nuisance.

As previously discussed, a health risk assessment was performed by the applicant for the project. The cancer risk does not exceed one in one million. The acute and chronic hazard indexes do not exceed 1. A health index of 1 is the maximum a source should be allowed to contribute to the existing background risk. The indices are less than one.

A nuisance is not anticipated and will be prohibited by a permit condition.

RULE 209 FOSSIL FUEL-STEAM FACILITY

Rule 209, Fossil Fuel-Steam Facility limits the emissions of sulfur oxides to 200 pounds per hour, nitrogen oxides to 140 pounds per hour and combustion contaminants to 10 pounds per hour from any fossil fired steam generating plant (as defined in Rule 102, Definitions).

Rule 102, Definitions, Section 226, Fossil Fuel, lists natural gas as a fossil fuel. Section 227, Fossil Fuel Fired Steam Generator, defines a fossil fuel-fired steam generator as "a furnace or boiler used in the process of burning fossil fuel for the primary purpose of producing steam by heat transfer. "

Each of the CTG/HRSG units produce electricity by three means: (1) momentum transfer from the gas turbine engine exhaust gasses to the power output shaft via the turbine blades, (2) indirect heat transfer from the turbine exhaust gases (after the turbine vanes) to water and steam tubes in the HRSG which produces steam which passes through a steam turbine/generator, and (3) duct firing within the HRSG to raise the temperature of the exhaust gases to transfer additional heat to the water and steam tubes in the HRSG producing additional steam generating more power in the steam turbine/generator. Under average ambient conditions, 86 to 94 MW are produced directly by the CTGs and 30 to 88 MW are produced indirectly by the HRSG (depending upon level of HRSG duct firing).

The CTG/HRSG equipment meets the definition of fossil fuel-steam generator because they produce a significant portion of the power through heat transfer. Rule 209, Fossil Fuel-Steam Facility, applies to the CTG/HRSG.

This rule also applies to the auxiliary boiler. The boiler emissions are below the required emission levels. Compliance with this rule is expected.

The calculated emissions are below the required emission levels. Compliance with this rule is expected.

RULE 210 SPECIFIC CONTAMINANTS

Rule 210, Specific Contaminants, limits the emission rates of sulfur compounds calculated as sulfur dioxide to 0.2 percent by volume for the Sacramento Valley and Mountain Counties Air Basin portions of the Placer County Air Pollution Control District. Combustion contaminants are limited to 0.1 grains per cubic foot of gas calculated at 12 percent carbon dioxide (CO2) at standard conditions. Combustion contaminants are defined in Rule 102, Definitions, as any particulate matter.

GE Turbine Calculations

Ambient Dry Bulb Temperature	34 degrees F
SO_2 Emission Rate at Peak	1.0 lbs/hr
PM-10 Emission Rate at Peak	4.6 lbs/hr
Exhaust Flowrate at Peak	1,093,524 lbs/hr
Exhaust Molecular Weight (MW)	28.5004
Percent Moisture of Exhaust	10.24%
Percent CO_2	4.70 %
SO_2 Molecular Weight (MW)	64.0628
Molar Volume	385.3 scf/lb mole

$$\text{Sulfur ppm} = \frac{(SO_2\ \text{lbs/hr}) \times \text{Exhaust MW} \times 1{,}000{,}000}{(\text{Flowrate lbs/hr}) \times (1\text{-\%moisture}) \times SO_2\ \text{MW} \times 60}$$

$$= 0.007554\ \text{ppmv} = 7 \times 10^{-7}\ \%$$

$$\text{PM-10 Concentration} = \frac{(\text{PM-10lbs/hr})\text{x}(1\text{hr}/60\text{min})\text{x}7000\ \text{grains/lb x } 12/\%\text{CO}}{(\text{Flowrate lbs/hr}) \text{ x } (60\text{sec/min}) \text{ x } (1\text{-\%moisture})/(\text{Exhaust MW}) \text{ x } (\text{Molar Volume})}$$

$$= 0.000172\ \text{grains/scf @}12\%CO_2$$

Alstom Turbine Calculations

Ambient Dry Bulb Temperature	34 degrees F
SO_2 Emission Rate at Peak	1.0 lbs/hr
PM-10 Emission Rate at Peak	4.7 lbs/hr
Exhaust Flowrate at Peak	1,063,331 lbs/hr
Exhaust Molecular Weight (MW)	28.5004
Percent Moisture of Exhaust	7.16%
Percent CO_2	3.46 %
SO_2 Molecular Weight (MW)	64.0628
Molar Volume	385.3 scf/lb mole

$$\text{Sulfur ppm} = \frac{(SO_2\ \text{lbs/hr}) \times \text{Exhaust MW} \times 1{,}000{,}000}{(\text{Flowrate lbs/hr}) \times (1-\%\text{moisture}) \times SO_2\ \text{MW} \times 60}$$

$$= 0.007512\ \text{ppmv} = 7.5 \times 10^{-7}\ \%$$

$$\text{PM-10 Concentration} = \frac{(\text{PM-10lbs/hr})\text{x}(1\text{hr}/60\text{min})\text{x}7000\ \text{grains/lb x } 12/\%\text{CO}}{(\text{Flowrate lbs/hr}) \times (60\text{sec/min}) \times (1-\%\text{moisture})/(\text{Exhaust MW}) \times (\text{Molar Volume})}$$

$$= 0.000238\ \text{grains/scf @}12\%CO_2$$

Sulfur dioxide emissions are less than 0.2%. Combustion contaminants are less than 0.1 grains/dscf. Compliance is expected and will be required by a permit condition.

RULE 211 PROCESS WEIGHT

Rule 211, Process Weight, establishes PM emission limits as a function of process weight rate in tons/hr. Natural gas fuels are excluded from the definition of process weight by Rule 102, Definitions, Section 243, Process Weight per Hour.

This rule does apply to the cooling towers.

Weight rate = 54,414 gal/min * 60 min/hr * 8.34 lb/gal / 2000 lb/ton

= 13,614 ton/hr

Rule 211 emission limit

$PM = 17.31 * P^{0.16}$ where P = tons per hour
PM = 79.3 pound/hour

The emission rate from the three cooling towers is 0.68 pounds/hour. This rate is less than the limit calculated above. Compliance is expected.

RULE 218 ARCHITECTURAL COATINGS

Rule 218, Architectural Coatings, limits the VOC content of architectural coating sold or used in Placer County. Compliant coatings are generally available. Compliance is expected.

RULE 220 ABRASIVE BLASTING

Rule 220, Abrasive Blasting, incorporates by reference the requirements of Title 17, Subchapter 6 of the California Administrative Code.

Compliance is expected.

RULE 221 COMPLIANCE TESTS

Rule 221, Compliance Tests, except as otherwise stated, performance tests undertaken to determine compliance of sources with Regulation II must comply with the provisions of CFR 40, Part 60, Appendix A except that Method 5 shall be modified to include the impinger train catch.

Compliance is expected.

RULE 231 INDUSTRIAL, INSTITUTIONAL AND COMMERCIAL BOILERS, STEAM GENERATORS AND PROCESS HEATERS

Rule 231 applies to boilers with rated heat inputs greater than or equal to 5 million Btu per hour used in industrial, institutional or commercial operations.

For natural gas fired units which use an annual heat input greater than or equal to 90,000 therms, NOx emissions are limited to 30 ppmv or 0.36 lbs/MMBtu. Carbon monoxide emissions are not to exceed 400 ppmv.

The project proposes to limit emissions of NOx to 9 ppmv and CO to 50 ppmv using an ultra low NOx burner and flue gas recirculation.

These emission levels comply with this rule.

RULE 250 GAS TURBINES

Rule 250, Gas Turbines, requires the CTGs to emit NOx at levels of no greater than the following except during the thermal stabilization:

9 x EFF/25 ppm, @ 15% O2, under load conditions, averaged over 15 minutes.

Where: EFF(efficiency) is the higher of the following:

$$EFF = \frac{3412 \times 100\%}{AHR}$$

AHR = Actual Heat Rate at HHV of Fuel (BTU/KW-HR)]

= 7,540 at base load
= 8,825 at peak load

or

$$EFF = \frac{MRE \times LHV}{HHV}$$

MRE = Manufacturer's Rated Efficiency with air pollution equipment at LHV

Given that the proposed project is a combined cycle facility, only the former calculation is appropriate.

$$\text{NOx limit} = \frac{(9 \times 3412 \times 100\%)}{7{,}540 \times 25} = 16.3 \text{ ppmv base load}$$

$$= \frac{(9 \times 3412 \times 100\%)}{8{,}825 \times 25} = 13.9 \text{ ppmv peak load}$$

The proposed NOx emission level of 2 ppmv @ 15% O_2 is below the emission levels required by this rule. Compliance is expected.

RULE 502 NEW SOURCE REVIEW

Section 301, Best Available Control Technology requires the application of best available control technology if emissions from an emission unit exceeds the trigger levels shown below:

Pollutant	lb/day
Reactive organic compounds	10
Nitrogen oxides	10
Sulfur oxides	80
PM10	80
Carbon monoxide	550
Lead	3.3
Vinyl chloride	5.5
Sulfuric acid mist	38
Hydrogen sulfide	55
Total reduced sulfur compounds	55
Reduced sulfur compounds	55

BACT is triggered for the combustion turbines, HRSGs, auxillary boiler, emergency generator and the fire pump. The proposed emission levels are expected to comply with this section.

Section 302, Offsets General, requires offsets if the facility emissions exceed the following levels:

Pollutant	pounds per quarter
Reactive organic compounds	7,500
Nitrogen oxides	7,500
Sulfur oxides	12,500
PM10	7,500
Carbon monoxide	7,500

Offsets for increases in carbon monoxide are not required if the applicant, using an air quality modeling analysis prepared pursuant to Section 402, demonstrates to the satisfaction of the Air Pollution Control Officer that the increase in ambient concentration does not exceed 500 micrograms per cubic meter, 8 hour average, at or beyond the property line of the stationary source.

The proposed equipment will have emissions which exceed the offset trigger levels for NOx, PM-10 and CO. Modeling has indicated that emissions will not increase ambient concentrations by 500 micrograms per cubic meter on an eight-hour average with the exception of commissioning of the Alstom turbine. The modeling was based on a maximum of 1000 pounds per hour of CO. CO emissions and ambient air impacts are much higher during commissioning because the oxidation catalyst is not in place to control the CO emissions. This equals 8000 pounds in an eight hour period. In order to prevent CO impacts of more than 500 micrograms per cubic meter, the CO emissions during commissioning operations must be limited to no more than 500/603.2 X 1000 pounds or 829 pounds per hour. This will be a condition of the permit.

Offsets are required for PM-10 and NOx. CO offsets are not required.

Roseville Electric has identified PM-10 ERCs in sufficient quantities to offset the project. Roseville Electric has identified a portion of the NOx ERCs. They are proposing to use interpollutant trading and provide additional NOx ERCs. Compliance with offsets cannot be fully determined at this time.

I. COMPLIANCE WITH STATE AND FEDERAL AIR RULES AND REGULATIONS

40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines

Roseville Electric is required to meet the notification, recordkeeping and performance test requirements of this regulation. Roseville Electric must submit a written quarterly excess emission report to the Administrator. A performance test is required within 60 days of achieving maximum production or no later than 180 days of initial startup.

Federal Prevention of Significant Deterioration (PSD)

The PSD program applies to any new facility which is one of the 28 PSD categories in the Federal Clean Air Act and emits more than 100 tons per year of any regulated pollutant. The facility does fall into one of the 28 PSD categories but does not have a potential to emit of greater than 100 tons per year of a regulated pollutant. The facility is not required to comply with PSD.

California Air Resources Board Airborne Toxic Control Measure for Stationary Compression Ignition Engines

The diesel engines driving the emergency generator and the fire pump will be required to meet the requirements of the California Air Resources Board Airborne Toxic Control Measure for Stationary Compression Ignition Engines when it becomes effective. This regulation is currently undergoing a 15 day notice with comments due June 1, 2004. The effective date is expected to be January 1, 2005.

This regulation establishes control level for diesel engines. The regulation does allow a stationary emergency engine to limit hours of operation for maintenance and testing to 20 hours per year instead of meeting additional control requirements or emission levels.

Compliance is expected.

Health and Safety Code Section 40709.6, Offset System

Health and Safety Code Section 40709.6, Offset System, requires inter-district offsets to be approved by a resolution of the governing boards of both the upwind air district, where the emission reductions are to be credited (i.e. where the reductions occur, and from which the ERCs are transferred), and the downwind air district, where the emission increases are to be offset (i.e. where there will be emission increases requiring the use of ERCs). This authority may be delegated to the District Air Pollution Control Officer (APCO), and the District Board did delegate the authority to approve offsets credited pursuant to Health and Safety Code Section 40709.6, Subpart (a), by Resolution #98-11 adopted June 11, 1998. For this project, the APCO has indicated he will ask the District Board to consider the matter of inter district transfers in accordance with H&S 40709.6.

This requirement needs to be addressed before a final determination can be made.

RECOMMENDATION

The PCAPCD has made the following findings:

1. The equipment and emission limits proposed by the applicant are expected to meet BACT.

2. Offsets are required for NOx and PM-10. Six ERC certificates have been identified as offsets for emission increases of NOx and PM-10. Other potential sources of ERCs have been outlined but specific ERC certificates have not been disclosed to the District or the Energy Commission. Identification of the additional offsets required to offset the all emission increases of NOx and PM-10 plus the following information is required before a final Determination of Compliance is issued:

   A. The ERC certificate number, quantities for each quarter, location of the source of ERCs, distance of source of ERCs from the Roseville Energy Park and offset ratio.

   B. VOC emissions proposed to be traded for NOx will need to be further adjusted by an interpollutant trading ratio. Roseville Electric has proposed a ratio of 2.6. The offset ratio for the VOC for NOx trading is 2.0. The overall ratio of 5.2 to 1 is higher than used on other power plant projects. Additional modeling will be required to make a final determination of the trading ratio unless EPA concurs that a 5.2 overall ratio is acceptable.

   C. The offsets must be summarized in a table showing the amount of offsets provided for each pollutant requiring offsets for each quarter after adjustment for offset ratio and interpollutant trading ratio.

   D. For ERCs credited to a stationary source located in another air district than PCAPCD, Roseville Electric must obtain approval from their governing Board of the transfer of ERCs for use in Placer County to offset the REP. It is our understanding that this Board item is to be heard on June 9, 2004 at Yolo-Solano AQMD.

   E. Roseville Electric must also obtain approval of the PCAPCD Board for the transfer of ERCs for use in Placer County. This Board item is scheduled for June 10, 2004.

3. Notwithstanding the above item #2, the project is expected to meet the requirements of other applicable PCAPCD Rules and Regulations subject to the proposed conditions shown on the following pages.

The PCAPCD staff recommend the following mitigation for the construction activities for the REP project.

CONSTRUCTION MITIGATION

1. All of the measures proposed by the applicant and listed in the Application for Certification are required.

2. Limit traffic speeds on unpaved roads to 10 miles per hour.

3. Suspend all land cleaning, grading, earth moving and excavation activities when wind speeds exceed 20 miles per hour.

4. Apply water to active construction sites and unpaved roads hourly to control fugitive dust. At a minimum, there shall be one water truck operating for every three pieces of earth moving equipment.

5. Visible emissions shall not be seen crossing the property line.

6. Apply a non-toxic solid stabilizer to all inactive construction areas (previously graded areas which remain inactive for 96 hours).

7. No dry mechanical sweeping on or off-site.

8. Re-establish ground cover on the construction site through seeding and watering as soon as possible, but no later than final occupancy.

9. Limit construction vehicles and equipment idle time to no more than five minutes.

10. The project owner shall maintain a daily log of water truck activities, including record of the frequency of public road cleaning. These logs and records shall be available for inspection by the PCAPCD during the construction period. The applicant shall make the construction site available to the PCAPCD staff for inspection and monitoring.

11. The prime contractor shall submit to the District a comprehensive inventory (i.e. make, model, year, emission rating) of all the heavy-duty off-road equipment (50 horsepower of greater) that will be used an aggregate of 40 or more hours for the construction project. District personnel will conduct initial Visible Emission Evaluation of all heavy-duty equipment on the inventory list.

12. The project shall provide a plan for approval by the District demonstrating that the heavy-duty (> 50 horsepower) off-road vehicles to be used in the construction project, including owned, leased and subcontractor vehicles,

will achieve a project wide fleet-average 20 percent NOx reduction and 45 percent particulate reduction compared to the most recent CARB fleet average. The District should be contacted for average fleet emission data. Acceptable options for reducing emissions may include use of late model engines, low-emission diesel products, alternative fuels, engine retrofit technology, after-treatment products, and/or other options as they become available.

13. An enforcement plan shall be established to weekly evaluate project-related on-and-off- road heavy-duty vehicle engine emission opacities, using standards as defined in California Code of Regulations, Title 13, Sections 2180 - 2194. An Environmental Coordinator, CARB-certified to perform Visible Emissions Evaluations (VEE), shall routinely evaluate project related off-road and heavy duty on-road equipment emissions for compliance with this requirement. Operators of vehicles and equipment found to exceed opacity limits will be notified and the equipment must be repaired within 72 hours.

14. No open burning of removed vegetation during infrastructure improvements. Vegetative material should be chipped or delivered to a waste to energy facility.

15. The contractor shall use oxidizing soot filters, oxidizing catalysts and emulsified diesel fuel for all pre-1996 offroad diesel engines driven equipment.

16. The applicant shall use diesel fuel certified to CARB low sulfur fuel standards and diesel engines that are either equipped with high pressure fuel injection or employ fuel injection timing retardation.

OPERATIONAL MITIGATION

17. Landscape with native drought-resistant species (plants, trees and bushes) to reduce the demand for gas powered landscape maintenance equipment.

18. All truck loading and unloading docks shall be equipped with one 110/208 volt power outlet for every two dock doors. Diesel trucks shall be prohibited from idling more than five minutes and must be required to connect to the 110/208 volt power to run any auxiliary equipment. Signage shall be provided.

19. HVAC units shall be equipped with PremAir (or other manufacturer) catalyst system if available and economically feasible at the time building permits are issued. The PremAir catalyst can convert up to 70% of ground level ozone that passes over the condenser coils into oxygen. The PremAir

system is considered feasible if the additional cost is less than 10 percent of the base HVAC unit.

20. The roads and parking areas at the plant shall be paved.

21. Off road equipment such as forklifts shall utilize electric or propane for drive power whenever possible.

The PCAPCD staff recommend the following permit conditions for the REP project:

SPECIFIC FACILITY CONDITIONS

OFFSETS

1. If the GE LM-6000 turbines are selected, emission offsets shall be provided for all calendar quarters for NOx and PM-10 in the following amounts, at the offset ratio specified in the condition 5. (Offsets are not required for CO, SOx and VOC emissions.)

Table 37 – GE LM6000 - OFFSETS REQUIRED					
POLLUTANT	QUARTER 1 (lbs/quarter)	QUARTER 2 (lbs/quarter)	QUARTER 3 (lbs/quarter)	QUARTER 4 (lbs/quarter)	Tons/year
NOx	17,857	16,015	19,357	19,243	36.24
PM-10	17,523	15,246	18,999	18,788	35.28

2. If the Alstom GX100 turbines are selected, emission offsets shall be provided for all calendar quarters for NOx and PM-10 in the following amounts, at the offset ratio specified in the condition 5. (Offsets are not required for CO, SOx and VOC emissions.)

Table 38 - ALSTOM GX100 - OFFSETS REQUIRED					
POLLUTANT	QUARTER 1 (lbs/quarter)	QUARTER 2 (lbs/quarter)	QUARTER 3 (lbs/quarter)	QUARTER 4 (lbs/quarter)	Tons/year
NOx	19,215	18,911	20,429	20,541	39.55
PM-10	17,854	15,513	19,378	19,158	35.95

3. NOx and VOC emission reductions that occurred during calendar quarter 2, beginning April 1, and calendar quarter 3, beginning July, 1 may be used to offset increases in NOx and VOC during any quarter of the year.

4. PM-10 emission reductions that occurred during calendar quarter 1, beginning January 1, and calendar quarter 3, beginning October 1, may be used to offset increases in PM-10 during any quarter of the year.

5. The applicant shall provide offsets according to the offset ratios shown in the following table. These ratios are listed in the current Rule 502, New Source Review (8/09/01) with the exception of the ratio for non-attainment pollutants within 15 mile radius and within the District. The U.S. EPA requires a minimum offset ratio of 1.3 for non-attainment pollutants.

Table 39– Offset Ratios	
Location of Offset	NOx and PM-10
Within 15-Mile Radius and within the District	1.3 to 1.0
Within 15-Mile Radius, outside the District, but within the same air basin	1.3 to 1.0
Greater than 15-Mile but within 50-Mile Radius and within District	2.0 to 1.0
Greater than 15-Mile but within 50-Mile Radius and outside the District, but within the same air basin	2.1 to 1.0
More than 50-Mile Radius and within the same air basin	2.2 to 1.0

6. VOC emissions proposed to be traded for NOx will need to be further adjusted by an interpollutant trading ratio. Roseville Electric has proposed a ratio of 2.6. The offset ratio for the VOC for NOx trading is 2.0. The overall ratio of 5.2 to 1 is higher than used on other power plant projects. Additional modeling will be required to make a final determination of the trading ration unless EPA concurs that a 5.2 overall ratio is acceptable.

7. Offsets shall only come from regions with the same air quality designations or worse designations than that of the emissions unit or stationary source requiring the offsets.

8. Prior to the final determination of compliance, for ERCs credited to a stationary source located in another air district than PCAPCD, the governing board of the district where the emission reductions are credited shall approve by a resolution the crediting of the emission offsets for use in PCAPCD.

9. Prior to the final determination of compliance, Roseville Electric shall appear before the PCAPCD District Board and gain approval by a resolution of ERCs that were credited to a stationary source located in another air district.

10. Roseville Electric must demonstrate by written documentation that all necessary offsets have been acquired or that binding contracts to secure such offsets have been entered into prior to the final determination of compliance.

11. All required ERC certificates shall be submitted to the PCAPCD at least 30 days prior to start of construction. Copies shall be submitted to the Energy Commission CPM by that date.

12. In addition to additional offsets which are required, the ERC certificates to be surrendered shall include the following ERCs which have been identified for offsets for this project:

Table 40 – ERCs Currently Identified						
NOx	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-23	5,050	5,050	5,050	5,050	10.1
Calpine Corp.	YSAQMD/ EC-209 (EC-238)	0	6,888	0	3,542	5.22
Calpine Corp.	YSAQMD/ EC-210	0	10,620	0	4,414	7.52
NOx	Totals	5,050	22,558	5,050	13,006	22.8
VOCs for NOx	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-26	33,512	33,512	33,512	33,512	67.0
VOCs for NOx	**TOTALS**	33,512	33,512	33,512	33,512	67.0
PM-10	District/ Certificate #	Quarter 1 (lbs)	Quarter 2 (lbs)	Quarter 3 (lbs)	Quarter 4 (lbs)	Annual (Tons)
Enron North America	PCAPCD/ 2001-24	14,700	14,700	14,700	14,700	29.4
Enron North America	PCAPCD/ 2001-22	2,578	22,263	16,085	15,916	28.4
PM-10	**TOTALS**	17,278	36,963	30,785	30,616	57.8

13. The gas turbines and auxillary boiler shall be fired exclusively on pipeline grade natural gas.

14. Roseville Electric shall maintain an Operating Compliance Plan for the new CTG/HRSG which will assure that the air pollution control equipment will be properly maintained and that necessary operational procedures are in place to continuously achieve compliance with this permit. The Operating

Compliance Plan shall include a description of the process monitoring program and devices to be provided.

A. The plan shall specify the frequency of surveillance checks that will be made of process monitoring devices and indicators to determine continued operation within permit limits. A record or log of individual surveillance checks shall be kept to document performance of the surveillance.

B. The plan shall include the frequency and methods of calibrating the process monitoring devices.

C. The plan shall specify for each emission control device:
   i. Operation and maintenance procedures that will demonstrate continuous operation of the emission control device during emission-producing operations; and
   ii. Records that must be kept to document the performance of required periodic maintenance procedures.

D. The plan shall identify what records will be kept to comply with air pollution control requirements and regulations and the specific format of the records. These records shall include at least the Recordkeeping information required by this permit. The information must include emission monitoring evaluations, calibration checks and adjustments, and maintenance performed on such monitoring systems.

E. The plan shall be submitted to the District 30 days prior to startup of the gas turbines and boiler. The plan must be implemented upon approval by the Air Pollution Control Officer.

F. The plan shall be resubmitted to the District for approval upon any changes to compliance procedures described in the plan, or upon the request of the Air Pollution Control Officer

15. CEMS Remote Polling:

A. Roseville Electric shall install and maintain equipment, facilities, software and systems at the facility and at the District office that will allow the District to poll or receive electronic data from the CEMS. Roseville Electric shall make CEMS data available for automatic polling of the daily records. Roseville Electric shall make hourly records available for manual polling within no more than a one hour delay. The basic elements of this equipment include a telephone line, modem and datalogger. Alternatively, an internet based system may be used. The costs of installing and operating this equipment, excluding District costs, shall be borne by the REP.

B. Upon notice by the District that the facility's polling system is not operating, the REP shall provide the data by a District-approved alternative format and method for up to a maximum of 30 days.

C. The polling data is not a substitute for other required recordkeeping or reporting. (Rule 404 § C; Rule 501 § 304.2.c; HSC 42706)

OPERATING LIMITATIONS

16. The hours of operation of each gas as turbines shall not exceed the following:

Table 41 – Power Plant Gas Turbine Operating Schedule

	1st	2nd	3rd	4th	Annual
Total operating hours	2,096	1,864	2,132	2,145	8,237

17. Permittee shall submit design details for the selective catalytic reduction, oxidation catalyst, and continuous emission monitor system to the PCAPCD at least 30 days prior to commencement of construction of these components.

18. Roseville Electric shall install a selective catalytic reduction (SCR) system and an oxidation catalyst on the gas turbine. The SCR and oxidation catalyst equipment shall be operated whenever the gas turbine is operated.

19. The gas turbine engine and generator lube oil vents shall be equipped with mist eliminators.

20. The gas turbines and auxiliary boiler shall be equipped with continuously recording, nonresettable fuel gas flowmeters on each unit.

21. Each gas turbine exhaust shall be equipped with continuously recording emissions monitor for NOx, CO, and 02 dedicated to this unit. Continuous emission monitor shall meet the requirements of 40 CFR parts 60 and 75, and shall be capable of monitoring emissions during startups and shutdowns as well as normal operating conditions. The system shall be installed and operational prior to initial startup of the turbines.

22. The gas turbine exhaust stacks and boiler exhaust stack shall be equipped with permanent provisions to allow collection of stack gas samples consistent with EPA test methods. Access ladders and/or stairs and platforms shall allow easy access to the sampling ports.

23. The gas turbine engine shall be fired exclusively on pipeline quality natural gas with a sulfur content no greater than 0.50 grains of sulfur compounds per 100 dry scf of natural gas.

24. Startup is defined as the period beginning with turbine light-off (firing) until the unit meets the lb/hr and ppmv emission limits in conditions 54, 58 and 59. Shutdown is defined the period beginning with initiation of turbine shutdown sequence and ending with cessation of firing of the gas turbine engine. Startup and shutdown durations shall not exceed 3.0 hours and 1 hour, respectively, per occurrence.

25. NOx, excluding the thermal stabilization period (i.e. startup period which is not to exceed 3 hours), shall not exceed the following levels under load conditions:

9 x EFF/25 ppm, @ 15% O2, averaged over 15 minutes:

Where: EFF(efficiency) is the higher of the following:

$$EFF_1 = \frac{3412 \times 100\%}{AHR}$$

AHR =Actual Heat Rate at HHV of Fuel (BTU/KW-HR)]

or

$$EFF_2 = \frac{MRE \times LHV}{HHV}$$

MRE = Manufacturer's Rated Efficiency with Air Pollution Equipment at LHV.], which is the manufacturer's continuous rated percent efficiency of the gas turbine with air pollution equipment after correction from LHV to HHV of the fuel at peak load for that facility.

COMMISSIONING

26. The commissioning period commences when all mechanical and electrical systems are installed and individual startup has been completed or when a gas turbine is first fired whichever comes first. The period ends when the plant has completed performance testing and is available for commercial operation.

27. The gas turbines shall be tuned to minimize the air emissions. At the earliest feasible time, in accordance with the recommendations of the equipment manufacturer and construction contractor, the air pollution control equipment shall be installed, adjusted and operated to minimize emissions from the combustion turbines.

28. The total number of firing hours of each gas turbine without abatement shall not exceed 160 hours during the commissioning period. Such operation shall only be limited to such activities that can only be properly executed without the air pollution control equipment.

29. During the commissioning operations, CO emissions shall not exceed 829 pounds per hour for any one-hour block average. Compliance to be determined by CEMS measurements. (This condition was established to prevent impacts from exceeding 500 ug/m3 over an 8-hour average).

30. The total mass emissions of each regulated pollutant that are emitted during the period shall not exceed the quarterly emission limits specified in these conditions.

REPORTING AND RECORDKEEPING

31. Submit to the Air Pollution Control Officer, prior to issuance of a Permit to Operate, information correlating the control system operating parameters to the associated NOx output. This information may be used by the Air Pollution Control Officer to determine compliance when there is no continuous emission monitoring system for NOx available or when the continuous emission monitoring system is not operating properly.

32. Provide source test information annually regarding the exhaust gas NOx concentration at ISO conditions corrected to 15 percent oxygen on a dry basis, and the demonstrated percent efficiency (EFF) of the turbine unit.

33. Maintain a gas turbine operating log that includes, on a daily basis, the actual Pacific Standard Time start-up and stop time, total hours of operation, type and quantity of fuel used (liquid/gas). This information shall be available for inspection at any time from the date of entry.

34. The permittee shall maintain hourly records of NOx and CO emission concentrations (ppmv @ 15% 02), and hourly, daily, and quarterly records of NOx and CO emissions. Ongoing compliance with the CO emission limits during normal operation shall be deemed compliance with the VOC emission limits during normal operation.

35. The permittee shall maintain records of SOx lb/hr, lb/day, and lb/quarter emissions. SOx emissions shall be based on fuel use records, natural gas sulfur content, and mass balance calculations.

36. The permittee shall maintain the following records: occurrence, duration, and type of any startup, shutdown, or malfunction; performance testing, evaluations, calibrations, checks, adjustments, any period during which a

continuous monitoring system or monitoring device was inoperative, maintenance of any continuous emission monitor; emission measurements, total daily and rolling twelve month average hours of operation, hourly quantity of fuel used, and gross three hour average operating load.

37. All records required to be maintained by this permit shall be maintained for a period of five years and shall be made readily available for District inspection upon request. 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.

38. The permitted shall notify the District of any breakdown condition as soon as reasonably possible, but no later than two PCAPCD business hours after its detection.

39. Any violation of any emission standard listed in this permit which is indicated by the CEMS shall be reported to the District no later than 96 hours after such occur per California Health and Safety Code 42706.

40. The District shall be notified in writing within seven calendar 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.

41. Audits of continuous emission monitors shall be conducted quarterly, except during quarters in which relative accuracy and total accuracy testing is 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.

42. The 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.

43. Roseville Electric 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 (if known), corrective actions taken and preventive measures adopted; averaging period used for data reporting shall correspond to the averaging period for each respective emission standard; applicable time and date of each period during which the 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.

44. Roseville Electric shall provide the District with a written emission statement showing actual emissions of volatile organic compounds and oxides of nitrogen. Pursuant to District Rule 503 Roseville Electric shall submit this emission statement on a form or in a format specified by the Air Pollution Control Officer. The statement shall contain the following information:

    A. Information contained in the California Air Resources Board's Emission Inventory Turn Around Document as described in Instructions for the Emission Data System Review and Update Report; and
    B. Actual emissions of volatile organic compounds and oxides of nitrogen, in tons per year, for the calendar year prior to the preparation of the emission statement; and
    C. Information regarding seasonal or diurnal peaks in the emission of affected pollutants; and
    D. Certification by a responsible official of Roseville Electric that the information contained in the emission statement is accurate to the best knowledge of the individual certifying the emission statement.

PERFORMANCE TESTING

45. Compliance with the short term emission limits (lb/hr and ppmv @ 15% 02) shall be demonstrated by a performance test conducted within 60 days of reaching maximum production and not later than 180 days from initial startup of each gas turbine engine.

46. A performance test shall be conducted annually for each combustion turbine/heat recovery steam generator unit each calendar year.

47. Compliance with the cold start NOx, and CO mass emission limits shall be demonstrated for one of the gas turbines engines upon initial operation and at least every seven years thereafter by performance testing by an ARB certified independent test firm.

48. The following test methods shall be used PM10: EPA method 5 (front half and back half), NOx: EPA Method 20, CO: EPA method 10 or 1 OB, 02: EPA Method 3A, VOC: EPA method 18, and fuel gas sulfur content: ASTM D3246. Alternative test methods as approved by the PCAPCD may also be used to address the source testing requirements of this permit.

EMISSION LIMITATIONS

49. No emissions are permitted, from any source, which are a nuisance per District Rule 205, <u>Nuisance</u>. (Rule 205)

50. Stack emission opacity as dark or darker than Ringelmann No. 1 (20% opacity) for period or periods aggregating more than three (3) minutes in any one hour is prohibited and is in violation of District Rule 202, Visible Emissions. (Rule 202)

51. Particulate matter emissions shall not to exceed 0.1 grains per cubic foot of gas calculated at 12 percent CO at standard conditions. (Rule 210)

52. Sulfur compound emissions calculated as SO2 shall not exceed 0.2 percent by volume. (Rule 210).

53. The ammonia slip shall not exceed 10 ppmv.

54. The emissions from the gas turbine after air pollution controls shall not exceed the following:

Table 42 - Gas Turbine PPMV Limitations Excluding Startup and Shutdown		
NO_X	CO	VOC
2.0 ppmvd @ 15% O_2, 1-hour average	4 ppmvd @ 15% O_2, 3-hour average	2 ppmv @ 15% O_2, 1-hour average

55. The 2.0 ppmvd NO_x emission limit is averaged over 1 hour at 15 percent oxygen, dry basis. The limit shall not apply to the first six (6) 1-hour average NOx emissions above 2.0 ppmvd, dry basis at 15% O2, in any calendar quarter period for each combustion gas turbine provided that it meets all of the following requirements:
   A. This equipment operates under any one of the qualified conditions ` described below:
      1. Rapid combustion turbine load changes due to the following conditions:
         i. Load changes initiated by the California ISO or a successor entity when the plant is operating under Automatic Generation Control; or
         ii. Activation of a plant automatic safety or equipment protection system which rapidly decreases turbine load
      2. The first two 1-hour reporting periods following the initiation/shutdown of a fogging system injection pump
      3. The first two 1-hour reporting periods following the initiation/shutdown of combustion turbine steam injection
      4. The first two 1-hour reporting periods following the initiation of HRSG duct burners

5. Events as the result of technological limitation identified by the operator and approved in writing by the District.

B. The 1-hour average NOx emissions above 2.0 ppmv, dry basis at 15% O2, did not occur as a result of operator neglect, improper operation or maintenance, or qualified breakdown under Rule 404, Upset Conditions, Breakdown or Scheduled Maintenance. Notification to the District is required within two hours of a qualified event.

C. The qualified operating conditions described in (A) above are recorded in the plant's operating log within 24 hours of the event, and in the CEMS by 5 p.m. the next business day following the qualified operating condition. The notations in the log and CEMS must describe the date and time of entry into the log/CEMS and the plant operating conditions responsible for NOx emissions exceeding the 2.0 ppmv 1-hour average limit. In addition, these excursions must be identified in the CEMS quarterly reports.

D. The 1-hour average NOx concentration for periods that result from a qualified operating condition does not exceed 25 ppmv, dry basis at 15 percent O2.

E. All NOx emissions during these events shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

56. If the GE LM6000 turbines are selected for the project, emission rates from each gas turbine and heat recovery steam generator exhaust during startup and shutdown shall not exceed the following:

Table 43 – GE LM6000 Combustion Turbine Emission Limitations during Startup and Shutdown

Pollutant	Maximum Pounds Per Hour (worst-case turbine)	Pounds per Startup or Shutdown (both turbines combined)
NO_x	19.3	49.7
CO	14.3	42.2
VOC	1.4	6.6
PM_{10}	3.2	19.0
SO_2	0.7	3.9

57. If the Alstom GX100 turbines are selected for the project, emission rates from each gas turbine and heat recovery steam generator exhaust during startup and shutdown shall not exceed the following:

Table 44 – Alstom GX100 Combustion Turbine Emission Limitations during Startup and Shutdown		
Pollutant	Maximum Pounds Per Hour (worst-case turbine)	Pounds per Startup or Shutdown (both turbines combined)
NO_x	37.1	122.8
CO	89.5	204.8
VOC	19.7	78.6
PM_{10}	3.2	19.3
SO_2	0.7	4.0

58. If the GE LM6000 turbines are selected for the project, emission rates from each gas turbine and heat recovery steam generator exhaust, except during startup and/or shutdown or excursions, shall not exceed the following:

Table 45 - GE LM6000 - COMBUSTION TURBINE EMISSION LIMITATIONS PER TURBINE EXCLUDING STARTUP AND SHUTDOWN	
POLLUTANT	POUNDS/HOUR
Carbon Monoxide (CO)	6.1 (three-hour rolling average)
Nitrogen Oxides (NOx)	5.0 (one-hour average)
PM-10	4.6
Sulfur Oxides (SOx)	1.0
Volatile Organic Compounds (VOCs)	1.7

59. If the Alstom GX100 turbines are selected for the project, emission rates from each gas turbine and heat recovery steam generator exhaust, except during startup and/or shutdown, or excursions shall not exceed the following:

Table 46 - Alstom GTX100 - COMBUSTION TURBINE EMISSION LIMITATIONS PER TURBINE EXCLUDING STARTUP AND SHUTDOWN	
POLLUTANT	POUNDS/HOUR
Carbon Monoxide (CO)	6.2 (three-hour rolling average)
Nitrogen Oxides (NOx)	5.1 (one-hour average)
PM-10	4.7
Sulfur Oxides (SOx)	1.0
Volatile Organic Compounds (VOCs)	1.8

60. If the GE LM6000 turbines are selected for the project, the daily emissions shall not exceed the following rates:

Table 47 – GE LM6000 - DAILY EMISSION LIMITS					
POLLUTANT	Two GE Turbines	Auxiliary Boiler	Cooling Tower	Diesel Emergency Generator	Diesel Fire Pump
NO_x	268.7	16.8	--	4.31	1.72
CO	300.8	52.8	--	0.84	0.09
VOC	83.6	7.2	--	0.16	0.05
PM_{10}	221.6	14.4	16.3	0.14	0.03
SO_2	46.0	1.92	--	0.10	0.19

61. If the Alstom GX100 turbines are selected for the project, the daily emissions shall not exceed the following rates:

Table 48 – Alstom GX100 - FACILITY DAILY EMISSION LIMITS					
POLLUTANT	Two Alstom Turbines	Auxiliary Boiler	Cooling Tower	Diesel Emergency Generator	Diesel Fire Pump
NO_x	406.0	16.8	--	4.31	1.72
CO	629.5	52.8	--	0.84	0.09
VOC	223.1	7.2	--	0.16	0.05
PM_{10}	226.8	14.4	16.3	0.14	0.03
SO_2	47.1	1.92	--	0.10	0.19

62. If the GE LM6000 turbines are selected for the project, the total facility emissions shall not exceed the following quarterly emission rates:

Table 49 – GE LM6000 - FACILITY DAILY EMISSION LIMITS					
POLLUTANT	QUARTER 1 (lbs)	QUARTER 2 (lbs)	QUARTER 3 (lbs)	QUARTER 4 (lbs)	Tons/year
NO_x	17,857	16,015	19,357	19,243	36.24
CO	21,625	19,737	23,500	23,322	44.09
VOC	6,046	5,188	6,596	6,514	12.17
PM_{10}	17,523	15,246	18,999	18,788	35.28
SO_2	3,331	2,838	3,630	3,587	6.69

63. If the Alstom GX100 turbines are selected for the project, the total facility emissions shall not exceed the following quarterly emission rates:

Table 50- ALSTOM GX100 - FACILITY QUARTERLY EMISSION LIMITS					
POLLUTANT	QUARTER 1 (lbs)	QUARTER 2 (lbs)	QUARTER 3 (lbs)	QUARTER 4 (lbs)	Tons/year
NO_x	19,215	18,911	20,429	20,541	39.55
CO	27,121	33,872	28,515	30,202	59.86
VOC	5,832	7,455	6,672	6,890	13.42
PM_{10}	17,854	15,513	19,378	19,158	35.95
SO_2	3,400	2,893	3,709	3,663	6.83

64. 40 CFR 60 Subpart GG – Standards of Performance for Stationary Gas Turbines

The gas turbines are required to meet the notification, recordkeeping and performance test requirements of this regulation. Roseville Electric must submit a written quarterly excess emission report to the Administrator. A performance test is required within 60 days of achieving maximum production or no later than 180 days of initial startup.

COOLING TOWERS

OPERATING LIMITATIONS

65. Permittee shall submit drift eliminator design details at least 30 days prior to commencement of construction.

66. No hexavalent chromium containing compounds shall be added to water.

67. Drift eliminator drift rate shall not exceed 0.0005% of the circulating water flow.

PERFORMANCE TESTING

68. A water sample analysis of cooling tower water shall be performed within 180 days of initial operation and annually thereafter.

EMISSION LIMITATIONS

69. No emissions are permitted, from any source, which are a nuisance per District Rule 205, Nuisance. (Rule 205)

70. PM10 emission rate shall not the following rates:

Table 51 - COOLING TOWER EMISSION LIMITATIONS					
Pollutant	**POUNDS PER DAY**	**QUARTER 1** (Pounds/quarter)	**QUARTER 2** (Pounds/quarter)	**QUARTER 3** (Pounds/quarter)	**QUARTER 4** (Pounds/quarter)
PM-10	16.3	1,471	1,487	1,504	1,504

71. Compliance with the PM10 emission limit shall demonstrated as follows: PM10 = cooling water recirculation rate * total dissolved solids concentration in the blowdown water * design drift rate.

AUXILLARY BOILER

OPERATING LIMITATIONS

72. An ultra low NOx burner and flue gas recirculation system shall be installed and operated on the auxillary boiler.

73. A non-resetable fuel meter shall be installed on the gas line serving the boiler.

74. The hours of operation of the auxillary boiler shall not exceed the following:

Table 52 – Boiler Hours of Operation				
	Quarter 1	Quarter 2	Quarter 3	Quarter 4
Boiler Hours o f Operation	140	568	143	143

PERFORMANCE TESTING

75. Compliance with the boiler pounds per hour and ppmv emission limits shall be demonstrated by an initial performance test conducted within 60 days of reaching maximum production and not later than 180 days from initial startup.

76. The initial performance test shall be conducted for NOx, VOC, SOx, PM-10, CO, CO_2, and O_2.

77. Performance tests shall be conducted on the boiler every other calendar year after the initial testing. These tests shall include NOx, CO, CO_2, and O_2.

78. All boiler source tests shall be made in the as-found operating condition, except that source tests shall include at least one test conducted at the maximum feasible firing rate allowed by the District permit. No source test shall be conducted within two hours after a continuous period in which fuel flow to the unit is zero, or shut off, for thirty minutes or longer.

79. At least thirty (30) days prior to the compliance source tests, a written test plan detailing the test methods and procedures to be used shall be submitted for approval by the Air Pollution Control Officer. The plan shall cite the test methods to be used for the determination of compliance with the emission limitations of this rule.

80. A report of the compliance test shall be submitted to the District within sixty (60) days of completion of the source test.

EMISSION LIMITATIONS

81. The NOx emissions from the boiler shall not exceed 9.0 ppmv @ 3% 0_2 on a three hour average.

82. The CO emissions from the boiler shall not exceed 50 ppmv @ 3% 0_2 on a three hour average.

83. The boiler emissions shall not exceed any of the following:

Table 53 - BOILER EMISSION LIMITATIONS

Pollutant	POUNDS Per Hour	QUARTER 1 (Pounds/quarter)	QUARTER 2 (Pounds/quarter)	QUARTER 3 (Pounds/quarter)	QUARTER 4 (Pounds/quarter)
NO_x	0.7	92	372	94	94
CO	2.2	311	1,259	317	317
VOC	0.3	36	144	36	36
PM_{10}	0.6	82	332	84	84
SO_2	0.08	11	46	12	12

DIESEL FIRED IC ENGINES POWERING FIREWATER PUMP

OPERATING LIMITATIONS

84. Permittee shall submit IC engine design details to the District at least 30 days prior to commencement of construction.

85. A non-resettable hour meter shall be installed on each engine/generator set to record the hours of operation.

86. Operation for maintenance and testing of the emergency diesel engine and generator shall be limited to 100 hours per year.

87. Operation for other than maintenance and testing purposes shall be limited to involuntary interruptions of electrical power. Operation shall not exceed 24 hours without prior authorization by the Air Pollution Control Officer.

88. The sulfur content of the diesel fuel used shall not exceed 0.05% by weight.

REPORTING AND RECORDKEEPING

89. Records of operation and maintenance shall be kept by the Owner or Operator for a period of five years and shall be made available to the District upon request. Information required for reporting to the District includes, but is not limited to:

    A. The hours of operation the engine was run for maintenance and testing.

    B. The hours of operation the engine was run during interruption of electrical power.

    C. Records of the sulfur content of the diesel fuel used.

EMISSION LIMITATIONS

90. No emissions are permitted, from any source, which are a nuisance per District Rule 205, Nuisance.

91. Stack emission opacity as dark or darker than Ringelmann No. 1 (20% opacity) for period or periods aggregating more than three (3) minutes in any one hour is prohibited and is in violation of District Rule 202, Visible Emissions.

92. Particulate matter emissions shall not to exceed 0.1 grains per cubic foot of gas calculated at 12 percent CO at standard conditions.

93. Sulfur compound emissions calculated as SO2 shall not exceed 0.2 percent by volume.

94. Nitrogen oxide emissions from the fire pump diesel engine shall not exceed 6.9 grams per brake horsepower - hour. This may be demonstrated by manufacturer's emissions data sheet.

95. PM-10 emissions from the fire pump diesel engine shall not exceed 0.4 grams per brake horsepower - hour. This may be demonstrated by manufacturer's emissions data sheet.

96. The fire pump diesel engine shall meet the requirements of the California Air Resources Board Airborne Toxic Control Measure for Stationary Compression Ignition Engines when it becomes effective.

DIESEL IC ENGINE POWERING EMERGENCY GENERATOR

OPERATING LIMITATIONS

97. Permittee shall submit IC engine design details to the District at least 30 days prior to commencement of construction of the IC engine.

98. A non-resettable hour meter shall be installed on each engine/generator set to record the hours of operation.

99. Operation for maintenance and testing of the emergency diesel engine and generator shall be limited to 50 hours per year.

100. Operation for other than maintenance and testing purposes shall be limited to involuntary interruptions of electrical power. Operation shall not exceed 24 hours without prior authorization by the Air Pollution Control Officer.

101. The sulfur content of the diesel fuel used shall not exceed 0.05% by weight.

REPORTING AND RECORDKEEPING

102. Records of operation and maintenance shall be kept by the Owner or Operator for a period of five years and shall be made available to the District upon request. Information required for reporting to the District includes, but is not limited to:

    A. The hours of operation the engine was run for maintenance and testing.

B. The hours of operation the engine was run during interruption of electrical power.

C. Records of the sulfur content of the diesel fuel used.

EMISSION LIMITATIONS

103. No emissions are permitted, from any source, which are a nuisance per District Rule 205, Nuisance. (Rule 205)

104. Stack emission opacity as dark or darker than Ringelmann No. 1 (20% opacity) for period or periods aggregating more than three (3) minutes in any one hour is prohibited and is in violation of District Rule 202, Visible Emissions. (Rule 202)

105. Particulate matter emissions shall not to exceed 0.1 grains per cubic foot of gas calculated at 12 percent CO at standard conditions. (Rule 210)

106. Sulfur compound emissions calculated as SO_2 shall not exceed 0.2 percent by volume. (Rule 210).

107. Nitrogen oxide emissions from the emergency generator diesel engine shall not exceed 6.9 grams per brake horsepower - hour. This may be demonstrated by manufacturer's emissions data sheet.

108. PM-10 emissions from the emergency generator diesel engine shall not exceed 0.4 grams per brake horsepower - hour. This may be demonstrated by manufacturer's emissions data sheet.

109. The engine shall meet the requirements of the California Air Resources Board Airborne Toxic Control Measure for Stationary Compression Ignition Engines when it becomes effective.

PORTABLE EQUIPMENT

110. Portable equipment shall comply with all applicable requirements while operating at the facility, including District Permit and Prohibitory Regulations, or be State-registered portable equipment. State-registered portable equipment shall comply with State registration requirements. A copy of the State registration shall be readily available whenever the State-registered portable equipment is at the facility.

TITLE V CONDITION

111. The Owner/Operator shall file a complete application for a Title V permit pursuant to Rule 507, Federal Operating Permit Program by no later than one year after commencing operation.

PCAPCD GENERAL CONDITIONS

112. Authorization to construct the equipment listed and as prescribed in the approved plans and specifications is hereby granted, subject to the specified permit conditions. The construction and operation of listed equipment shall be conducted in compliance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted in the conditions. Deviation from the approved plans is not permissible without first securing approval for the changes from the Air Pollution Control Officer. (Rule 501)

113. Written notification shall be submitted to the District no later than seven (7) days after completion of construction. (Rule 501)

114. This permit shall be maintained on the premises of the subject equipment. (Rule 501)

115. The authorized District agents shall have the right of entry to any premises on which an air pollution emission source is located for the purpose of inspecting such source, including securing samples of emissions therefrom, or any records required to be maintained therewith by the District. (Rule 402)

116. In the event of any violation of the District Rules and Regulations, Roseville Electric shall take action to end such violation. (Rule 502)

117. Roseville Electric shall notify the District within two hours of any upset conditions, breakdown or scheduled maintenance which cause emissions in excess of limits established by District Rules and Regulations. (Rule 404)

118. Any alteration of the subject equipment, including a change in the method of operation, shall be reported to the District. Such alternations may require an Authority to Construct Permit. (Rule 501)

119. Exceeding any of the limiting condition is prohibited without prior application for, and the subsequent granting of a permit modification pursuant to District Rule 501, General Permit Requirements, Section 400.

120. In the event of a change of ownership, an application must be submitted to the District. Upon any change in control or ownership of facilities constructed, operated, or modified under authority of this permit, the requirements contained in this Authority to Construct shall be binding on all subsequent owners and operators. (Rule 501)

121. Compliance of the permitted facility is required with the provisions of the "Air Toxics `Hot Spots' Information and Assessment Act" of 1987 (Health and Safety Code Sections 44300 et seq.).

122. Performance Test Requirements: If the District finds that additional performance tests are required to determine compliance with District Rules and Regulations and Conditions of this Authority to Construct, reasonable written notice shall be provided to Roseville Electric. The performance tests shall be subject to the following restrictions (Rule 501):

A. At least thirty (30) days prior to the actual testing, a written test plan shall be submitted to the Air Pollution Control Officer detailing the sampling methods, analytical methods or detection principles to be used. The prior written approval of the Air Pollution Control Officer is required for the use of alternate test methods.

B. The District may require, upon reasonable written notice, the conduct by Roseville Electric of such emissions testing or analysis as may be deemed necessary by the District to demonstrate compliance with District Rules and Regulations and the limiting conditions of this permit.

C. Testing shall be conducted in accordance with 40 CFR 60, Appendix A, Methods, or equivalent methods approved by the State of California Air Resources Board (ARB) by reference in Title 17 of the California Administrative Code, or other methods specified by Roseville Electric and approved in writing by the Air Pollution Control Officer. Independent testing contractors and analytical laboratories shall be Air Resources Board certified for the test or analysis conducted. Particulate matter testing, if requested, shall include both filterable and condensed particulate matter (e.g. Method 5 modified to include impinger catch).

D. A report of the testing shall be submitted to the District no later than sixty (60) days after the source test is performed.

APPENDIX A

ACRONYMS

A

AFC - Application for Certification

APCD - Air Pollution Control District

APCO - Air Pollution Control Officer

ATC - Authority to Construct

B

BACT - Best Available Control Technology

C

CAA - U.S. Clean Air Act

CAAQS - California Ambient Air Quality Standards

CAPCOA - California Air Pollution Control Officers Association

CARB - California Air Resources Board

CCAA - California Clean Air Act

CEC - California Energy Commission (Please note that the Energy Commission prefers to not use the acronym "CEC" because of possible confusion with other agencies or companies with the same acronym. This document uses Energy Commission or just Commission instead.)

CEM - continuous emissions monitoring

CEQA - California Environmental Quality Act

cfm - cubic feet per minute

CFR - Code of Federal Regulations

cfs - cubic feet per second

CO - carbon monoxide

CO_2 - carbon dioxide

CPM - Compliance Project Manager

CT - combustion turbine

CTG - combustion turbine generator

D

E

EIR - Environmental Impact Report

Energy Commission – California Energy Commission

EPA - U.S. Environmental Protection Agency

F

FCAA - Federal Clean Air Act

FSA - Final Staff Assessment

G

g - grains

GEP - good engineering practice

gpd - gallons per day

gpm - gallons per minute

H

HHV - higher heating value

HRA - Health Risk Assessment

HRSG - heat recovery steam generator

I

J

kV - kilovolt

kW - kilowatt

L

LAER - Lowest Achievable Emission Rate

lbs - pounds

lbs/hr - pounds per hour

lbs/MMBtu - pounds per million British thermal units

LORS - laws, ordinances, regulations and standards

M

m (M) - meter, million, mega, milli or thousand

MCF - thousand cubic feet

mgd - million gallons per day

MW - megawatt (million watts)

MWh - megawatt hour

N

NAAQS - National Ambient Air Quality Standards

NESHAPS - National Emission Standards for Hazardous Air Pollutants

NO - nitrogen oxide

NO_2 - nitrogen dioxide

NO_x - nitrogen oxides

NSPS - New Source Performance Standards

NSR - New Source Review

O

O_3 - Ozone

O&M - operation and maintenance

P

PDOC - Preliminary Determination of Compliance

PM - particulate matter

PM10 - particulate matter 10 microns and smaller in diameter

PM2.5 - particulate matter 2.5 microns and smaller in diameter

ppb - parts per billion

ppm - parts per million

ppmvd - parts per million by volume, dry

PSD - Prevention of Significant Deterioration

PTO - Permit to Operate

Q

QA/QC - Quality Assurance/Quality Control

R

S

SCFM - standard cubic feet per minute

SCR - Selective Catalytic Reduction

SIC - Standard industrial classification

SIP - State Implementation Plan

SNCR - Selective Noncatalytic Reduction

SO2 - sulfur dioxide

SOx - sulfur oxides

SO4 - sulfates

T

TAC - Toxic Air Contaminant

TCF - trillion cubic feet

TPY - tons per year

TSP - total suspended particulate matter

U

USEPA - U.S. Environmental Protection Agency

V

VOC - volatile organic compounds

W

W - Watt

WAA - Warren-Alquist Act

APPENDIX B
BACT ANALYSIS

BACT DETERMINATION
COMBUSTION TURBINES

In preparing this analysis, the District staff reviewed the BACT determinations for combined cycle gas turbines listed in the CARB Guidance for Power Plant Siting and Best Available Control Technology, South Coast Air Quality Management District BACT Guidelines, San Joaquin Valley Air Quality Management District Guidelines, Bay Area Air Quality Management Guidelines and power projects approved by the Energy Commission.

CARB's Guidance for Power Plant Siting and Best Available Control Technology (June,1999) provided a comprehensive guidance on BACT determinations for power plants. This document identified BACT for combined cycle turbines as shown in Table B1.

TABLE B1 - CARB's Guidance for Power Plant Siting And Best Available Control Technology

CO	NOx	PM-10	SOX	VOCs
6 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average OR 2.0 ppmvd @ 15% O_2, 3-hour rolling average	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)	2 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per Mate (based on higher heating value)

Recent BACT determinations listed in BACT guidelines for combined cycle gas turbines by other air districts are summarized in the following table:

TABLE B2 - RECENT DETERMINATIONS LISTED IN BACT GUIDELINES for SCAQMD, SJVAPCD, and BAAQMD

District and Date	CO	NOx	PM-10	SOX	VOCs
BAAQMD (07/18/03)	4 ppmvd @ 15% O_2	2.0 ppmvd @ 15% O_2	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	(POCs) 2 ppmvd @ 15% O_2

SJVAPCD (3/30/01)	6 ppmvd @ 15% O_2	2.0 ppmvd @ 15% O_2	An emission limit corresponding to natural gas with fuel sulfur content of no more than 0.75 grain/100 scf.	An emission limit corresponding to natural gas with fuel sulfur content of no more than 0.75 grain/100 scf (no more than 0.55 ppmvd @ 15% O_2)	2.0 ppmvd @ 15% O_2 (1.5 ppmv @ 15% Technologically feasible)
SCAQMD* (1/30/04)	2 ppmvd @ 15% O_2, 3-hour average	2.0 ppmvd @ 15% O_2, 1-hour average	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)	2.0 ppmvd @ 15% O_2, 1-hour average

*1/30/2004 Vernon City Power and Light, Alstom GTX turbine

The BACT determinations found in Commission Decisions for large combined cycle power projects are summarized in the following table:

TABLE B3 - BACT DETERMINATIONS FOR GAS TURBINES
PROJECTS RECENTLY APPROVED BY THE CALIFORNIA ENERGY COMISSION

PROJECT	DATE	CO	NOx	PM-10	SOx	VOCs
Blythe Energy Blyth Energy LLC 520 MW	2/9/00	5 ppmvd @ 15% O_2, 3-hour rolling average 8.4 ppmvd with duct firing or when between 70 and 80 percent of full load	2.5 ppmvd @ 15% O_2, 1-hour average	Natural gas with fuel sulfur content of no more than 0.5 grain/100 scf on a rolling 12 month average	Natural gas with fuel sulfur content of no more than 0.5 grain/100 scf on a rolling 12 month average	1 ppmvd @ 15% O_2, 1-hour rolling average OR 0.0027 pounds per MMBtu (based on higher heating value)
Contra Costa Unit 8 Southern Energy	5/30/01	6 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average	.00588 lbs/MMbtu without duct burners, and	0.0028 lbs/hr	.0025 lb/MMbtu

530 MW				0.00584 with duct burners in operation		
Delta Energy Center Calpine and Bechtel 880 MW	2/9/00	10 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average	.00565 lb/MMBtu	.0007 lb/MMbtu	.00251 lbs/MMbtu
Elk Hills Sempra/OXY 500 MW	12/6/00	4 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average	.0012 g/dscf, 1hour average @3% CO_2	1.24 lbs/hr	2 ppmvd @ 15% O_2, 1-hour rolling average
High Desert Inland Group and Constellation Energy 720 MW	5/3/00	4 ppmvd @ 15% O_2, 24-hour average	2.5 ppmvd @ 15% O_2, 1-hour average	25.41 lbs/hr	1.51 lbs/hr (based on 1 ppmvd)	1 ppmvd @ 15% O_2, 1-hour rolling average
La Paloma Generating Co. McKittrick, CA 1048 MW	5/26/99	6 ppmvd @ 15% O_2, 3-hour rolling average at loads greater than 73% and 10 ppmv @15% O_2 at loads equal to or less than 73% on 3 hour average.	2.5 ppmvd @ 15% O_2, 1-hour average Dry low NOx combustors, SCR with ammonia injection and natural gas fuel	Natural gas fuel with sulfur content of no more than 0.75 grain/100 scf. Air inlet filter cooler, lube oil vent coalescer and natural gas fuel and less than 5% opacity visible emissions at lube oil vent	Natural gas fuel with sulfur content of no more than 0.75 grain/ 100 scf. Utility quality natural gas	0.4 ppmv @ 15% O_2 as propane (equivalent to 1.1 ppmv as CH_4
Los Medanos Energy Center (Formerly Pittsburg District Energy Center) 555 MW	8/17/99	6 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average	Natural gas fuel with sulfur content of no more than 0.75 grain/100 scf.	Natural gas fuel with sulfur content of no more than 0.75 grain/ 100 scf.	.0017 lbs/MMBtu
(Western) Midway Sunset Arco	3/21/01	6 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average			1.4 ppmvd @ 15% O_2, 1-hour rolling

500 MW						average
Moss Landing Duke Energy 1,060 MW	10/25/00	6 ppmvd @ 15% O_2, 3-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average			
Moutainview Thermo Ecotek 1,056 MW	3/21/01	6 ppmvd @ 15% O_2, 1-hour rolling average	2.5 ppmvd @ 15% O_2, 1-hour average	An emission limit corresponding to natural gas with fuel sulfur content of no more than 0.25 grain/100 scf.(Corresponds to .006 lbs/MMBtu	An emission limit corresponding to natural gas with fuel sulfur content of no more than .25 grain/100 scf (no more than 0..00071 lb/MMBtu	1.4 ppmvd @ 15% O_2, 1-hour rolling average
Otay Mesa Otay Mesa Generating Co. (Calpine) 510 MW	4/18/01	6 ppmvd @ 15% O2, 3-hour rolling average	2.0 ppmvd @ 15% O2, 3-hour average			2.0 ppmvd @ 15% O2, 3-hour average
Pastoria Enron 750 MW	12/10/00	6.0 ppmvd @ 15% O_2, 3-hour average	2.0 ppmvd @ 15% O_2, 3-hour average			2.0 ppmvd @ 15% O_2, 24-hour average
Sutter Power Plant Calpine Corp. Yuba City, CA 540 MW	4/19/99	4 ppmv @ 15% O_2 calendar day average	2.5 ppmvd @ 15% O_2, 1-hour average	PUC grade fuel corresponding to 0.7 gr/dscf	1 ppmv on a calendar day average	1 ppmv on a calendar day average
Three Mountain Power Odgen Pacific	5/16/01	4 ppmvd @ 15% O_2, 3-hour rolling	2.5 ppmvd @ 15% O_2, 1-hour average	.0012 g/dscf, 1hour average @3% CO_2	1.24 lbs/hr	2 ppmvd @

Power 500 MW		average				15% O_2, 1-hour rolling average
City of Vernon		2 ppmvd @ 15% O_2, 3-hour average	2.0 ppmvd @ 15% O_2, 1-hour average	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)	2.0 ppmvd @ 15% O_2, 1-hour average
SMUD Consumnes River Project 500 MW Unit 1	9/03	4 ppmvd @ 15% O_2, 3-hour rolling average	2.0 ppmvd @ 15% O_2, 1-hour average	Natural gas fuel with sulfur content of no more than 1 grain/100 scf and 9 lbs/hr	Natural gas fuel with sulfur content of no more than 1 grain/100 scf	1.4 ppmvd, 3hr average
Walnut Energy Center 250 MW	2/04	4. @ 15% O_2, 3-hour rolling average 0 ppmv @	2.0 ppmvd @ 15% O_2, 1-hour average	7.0 lbs/hr	1.05 lbs/hr	1.4 ppmvd @ actual stack % O_2

BACT Analysis for Nitrogen Oxide (NOx)

For the turbines the following potential NOx control technologies were identified:

Water Injection
Steam Injection
Catalytic combustors (XONON)
Dry Low-NOx combustor design (DLN)
Selective non-catalytic reduction (SNCR) (i.e. ammonia or urea injection)
Non-selective catalytic reduction (NSCR) (i.e. 3-way catalyst)
Selective catalytic reduction (SCR)
SCONOx

Water injection is a feasible option. Small amounts of water are injected into the combustor burner flame. NOx emissions are reduced by cooling the combustion temperatures. Water injection typically results in NOx control efficiency of 70% and emission levels below 42 ppmv at 15% O2.

Steam injection is a feasible option. Small amounts of steam are injected into the combustor flame. NOx emissions are reduced by cooling the combustion temperatures. Steam injection typically results in NOx control efficiency of 82% and emission levels below 25 ppmv at 15% O2.

Catalytic combustors use a catalyst bed to oxidize the fuel at lower temperatures than required in standard thermal combustion. The fuel is burned without a flame. The XONON combustors have been demonstrated in a 1.5 MW natural gas fired turbine at Silicon Valley Power in Santa Clara, California.

Dry Low NOx combustors are a feasible option. Lower NOx emission rates are achieved by minimizing combustion temperatures. Air and fuel are mixed before the combustion chamber. A lean air/fuel mixture optimizes the mixing of combustion air and fuel at peak flame temperatures. Dry Low NOx combustors can achieve reductions of up to 94%to 9 ppmvd of NOx at 15% O2.

Selective non-catalytic reduction (SNCR) involves the injection of ammonia or urea directly into the exhaust gases without use of a catalyst. This technology requires exhaust temperatures in the range of 1200° to 2000°F and is mainly associated with boiler or heater NOx control. The exhaust gas temperature is below the required temperature. This option was determined to be not feasible.

Non-selective catalytic reduction (NSCR) uses a catalyst without injected reagents. NSCR is only effective in a stoichiometric or fuel rich environment when combustion gas is nearly deplete of oxygen. Typical oxygen concentration in turbine exhaust is 14 to 16 percent. Therefore, NSCR is not technologically feasible for gas turbines.

Selective catalytic reduction (SCR) is a feasible option. SCR systems reduce NOx by injecting ammonia (NH3) into the exhaust stream followed by a catalyst. NOx, ammonia and water react to form nitrogen (N2) and water. The catalyst is installed downstream of the turbine in the heat recovery steam generator. SCR systems can achieve reductions of 80% to 95%.

The SCONOX system uses a catalyst to oxidize NO to NO_2. NO_2 is absorbed into the catalytic surface with a potassium carbonate coating. SCONOX does not inject agents and there no ammonia emissions. Operating data from Federal Cogeneration indicates SCONOX can achieve up to 98% control. SCONOX has also been demonstrated on a 22 MW turbine at the Sunlaw facility in Vernon, California.

The remaining feasible control technologies or combination of technologies are:

1. Dry low NOx Combustors with SCR or XONON or SCONOX.
2. Steam Injection with SCR or XONON or SCONOX
3. Water injection with SCR or XONON or SCONOX

Each option appears to be capable of meeting the latest BACT emission levels. Roseville Electric has proposed the use of dry low NOx combustors with SCR for the Alstom CGT option or water injection with SCR for the CGT to reduce NOx emissions to 2.0 ppmv @15% O2 on a 1 hour average basis. Our review of other recent BACT determinations found other approved projects that required this level as BACT for NOx.

BACT for NOx was determined to be 2.0 ppmv @15% O2 on a 1 hour average basis.

BACT Analysis for Carbon Monoxide

The following potential control techniques were identified: (1) use of natural gas fuel combustion controls and (2) installation of an oxidation catalyst were identified as a potential control technique.

Combustion controls can reduce CO emissions and the addition of an oxidation catalyst can achieve 80% to 90% reduction in CO emissions. The oxidation catalyst is the most effective control technique and has been achieved in practice.

The applicant proposes to utilize the combustion controls and oxidation catalyst to meet a level of 4 ppmvd @15% O_2 on a three-hour average for CO

This level is at least as stringent as control techniques CARB's Guidance for Power Plant Siting and Best Available Control Technology (June,1999) BACT determination. The most recent determinations in the San Joaquin Valley AQMD BACT determination and the Bay Area Air Quality Management District indicate BACT for CO as 6 ppmv @ 15% O2 and 4 ppmv @ 15% O2 respectively, 3 hour average. A recent determination (1/30/04) was listed by South Coast AQMD as 2 ppmvd @15% O2. This was for an Alstom GTX100 turbine at the City of Vernon.

The most recently approved power plant using combined cycle CTGs was the Walnut Energy Center. This project was approved at 4 ppmvd @ 15% O2, three-hour average.

This analysis determined BACT for CO is 4 ppmvd @15% O_2 three-hour rolling average.

BACT Analysis for VOCs

VOC emissions from CTGs are controlled by the same technology as CO emissions. These are combustion controls and oxidation catalysts.

The applicant proposes to utilize combustion controls and oxidation catalyst to reduce emissions to a level of 2 ppmvd @15% O_2 on a three-hour average. This level is consistent with the BACT determinations by CARB's Guidance for Power Plant Siting and Best Available Control Technology (June, 1999) BACT determination, BAAQMD, SJVAQMD BACT Guidelines and SCAQMD Guidelines shown in Tables B1 and B2.

This analysis determined BACT for VOCs is 2 ppmvd @15% O_2 on a one hour average.

BACT Analysis for PM-10

This analysis has found no specific control equipment available to reduce emissions of PM-10 from CTGs. CARB’s Guidance for Power Plant Siting and Best Available Control Technology (June, 1999) BACT Determination indicates the emissions are directly related to the fuel sulfur content of the natural gas available in the pipeline. In California, the natural gas is expected to have no more than 1 grain of sulfur per 100 standard cubic feet.

Roseville Electric has proposed that the natural gas will have no more than 0.5 grains per 100 standard cubic feet.

The use of natural gas with a sulfur content of no more than 0.5 grains per 100 standard cubic feet is considered BACT for PM-10.

BACT Analysis for SOx

This analysis has found no specific control equipment available to reduce emissions of SOx from CTGs. CARB’s Guidance for Power Plant Siting and Best Available Control Technology (June, 1999) BACT Determination indicates the emissions are directly related to the fuel sulfur content of the natural gas available in the pipeline. In California, the natural gas is expected to have no more than 1 grain of sulfur per 100 standard cubic feet.

Roseville Electric has proposed that the natural gas will have no more than 0.5 grains per 100 standard cubic feet.

The use of natural gas with a sulfur content of no more than 0.5 grains per 100 standard cubic feet is considered BACT for SOx.

BACT DETERMINATION
AUXILIARY BOILER

BACT is triggered for NOx for the Auxiliary Boiler. The following BACT Guidelines were reviewed for this size boiler:

TABLE B4 – RECENT BACT DETERMINATIONS FOR NOX FOR BOILERS	
San Joaquin Valley APCD > 20 MMBtu/hr	15 ppmvd @3% O2 achieved in practice 9.0 ppmvd @ 3% O2 technologically feasible with SCR
Bay Area Air Quality Management District > 50 MMBtu/hr	9.0 ppmvd @ 3% O2
South Coast Air Quality Management District 21 MMBtu/hr	9.0 ppmvd @ 3% O2

The most recent BACT determination at Placer County was a standby boiler that was being retrofitted. The determination concluded NOx BACT for a standby boiler was 20 ppmv @ 3% O2. This review did not find other specific NOx BACT determinations for auxiliary boilers with limited hours of operation at other Districts.

The applicant has proposed meeting a NOx level 9.0 ppmvd @ 3% O2. This review concluded that 9.0 ppmvd has been achieved in practice in some cases for this size boiler and is considered BACT for this project.

BACT DETERMINATION
Diesel Engine – Emergency Use

The standby generator and fire pump are driven by diesel engines. Both units trigger BACT for NOx.

The PCAPCD recent BACT determinations have considered BACT for NOx from emergency diesel engines as 6.9 grams per horsepower-hour. The fire pump diesel engine meets this level. The standby generator diesel engine listed in the application is above this level at 7.2 grams per horsepower-hour. The applicant was notified of this issue and agrees to provide an engine that meets this level.

APPENDIX C

Roseville Electric Revised Tables

REVISED EMISSIONS TABLES SUBMITTED BY ROSEVILLE ELECTRIC TO PCAPCD (4/9/04.)

The following tables replace those in the Authority to Construct application filed with the District.

Table 3.1-8. Expected total annual emission rate (tons/yr).

	NO_X	SO_2	CO	VOC	PM_{10}
LM 6000 PC SPRINT	36.24	6.69	44.09	12.17	35.28
Alstom GTX100	39.56	6.83	59.86	13.42	35.95

Table 3.1-12. Hourly emission rates for each turbine (lb/hr)[1].

Constituent	GE LM 6000 PC SPRINT		Alstom GTX100		ppmvd @15% O_2
	Peak lb/hr	Base lb/hr	Peak lb/hr	Base lb/hr	
NO_x	5	3.4	5.1	3.5	2
CO	6.1	4.2	6.2	4.2	4
VOC	1.7	1.2	1.8	0.4	--
PM_{10}	4.6	3.2	4.7	3.2	--
SO_2	1.0	0.7	1.0	0.7	--
NH_3	9.2	6.3	9.5	6.4	10

1 – Values correspond to the maximum hourly rates, and are based on an ambient temperature of 34°F; data shown in Appendix 3.1-A.

Table 3.1-14. Startup emissions summary.

	General Electric LM6000 PC Sprint	Alstom GTX100
Hot Start:		
Maximum hour (worst-case turbine)		
NO_x lb/hr	8.8	22.6
CO lb/hr	9.2	83.5
VOC lb/hr	1.4	19.6
PM_{10} lb/hr	3.2	3.2
SO_2 lb/hr	0.7	0.7
Total per start (both turbines combined)[1]		
NO_x lbs	15.9	34.1
CO lbs	16.3	160.8
VOC lbs	2.3	38.8
PM_{10} lbs	6.3	6.4
SO_2 lb/hr	1.3	1.3
Warm Start:		
Maximum hour (worst-case turbine)		
NO_x lb/hr	12.2	37.1
CO lb/hr	10.8	89.5
VOC lb/hr	1.4	19.7
PM_{10} lb/hr	3.2	3.2
SO_2 lb/hr	0.7	0.7
Total per start (both turbines combined)[1]		
NO_x lbs	29.2	88.1
CO lbs	27.6	188.1
VOC lbs	4.5	76.7
PM_{10} lbs	12.7	12.9
SO_2 lb/hr	2.6	2.7
Cold Start:		
Maximum hour (worst-case turbine)		
NO_x lb/hr	19.3	37.1
CO lb/hr	14.3	89.5
VOC lb/hr	1.4	19.7
PM_{10} lb/hr	3.2	3.2
SO_2 lb/hr	0.7	0.7
Total per start (both turbines combined)[1]		
NO_x lbs	49.7	122.8
CO lbs	42.2	204.8
VOC lbs	6.6	78.6
PM_{10} lbs	19.0	19.3
SO_2 lb/hr	3.9	4.0

1 – Values correspond to the emissions for each startup event.
See Appendix 3.1-A for details.

Table 3.1-15. Maximum operation emission rates.

	NO_X		SO_2		CO		VOC		PM_{10}	
	LM6000	GTX100	LM6000	GTX100	LM6000	GTX100	LM6000	GTX100	LM6000	GTX100
Maximum hourly[1] pounds per hour	43.8	79.3	2.09	2.14	31.7	182.1	3.9	39.8	10.6	10.8
Maximum daily pounds per day[2]	288.9	425.4	48.07	49.15	354.8	683.6	89.9	229.4	252.4	257.6
Maximum quarterly[3] tons/quarter	9.68	10.27	1.82	1.85	11.75	16.94	3.30	3.73	9.50	9.69
Maximum annual[3] tons/yr	36.24	39.56	6.69	6.83	44.09	59.86	12.17	13.42	35.28	35.95

1 – See Appendix 3.1-E10 for details.
2 – See Appendix 3.1-E11 for details.
3 – See Appendix 3.1-E12 for details.

Table 3.1-27. Comparison of emissions increase with PSD significance emissions levels.

Pollutant	Emissions (tons per year)		Significant emission levels (tons per year)	Significant?
	GE LM6000	Alstom GTX100		
NO_x	36.24	39.56	100	no
SO_2	6.69	6.83	100	no
VOC	12.17	13.42	100	no
CO	44.09	59.86	100	no
PM_{10}[1]	35.28	35.95	100	no

1 – Including cooling tower.

Table 3.1-30. Maximum potential to emit in pounds

	NO_X		SO_2		CO		VOC		PM_{10}	
	LM6000	Alstom	LM6000	Alstom	LM6000	Alstom	LM6000	Alstom	LM6000	Alstom
Quarterly[1]	19,360.8	20,544.9	3,630.4	3,709.2	23,499.7	33,872.4	6,596.2	7,455.0	18,998.6	19,378.0
Annual	72,486.7	79,112.3	13,385.3	13,665.1	88,183.4	119,710.4	24,344.6	26,848.5	70,555.3	71,902.9

1 – Values are taken from the highest total quarterly values shown in Appendix 3.1-E. This is a copy of Table 3.1-E12.

APPENDIX 3.1E
CALCULATION OF STARTUP, MAXIMUM HOURLY, DAILY,
QUARTERLY, AND ANNUAL EMISSIONS

Table 3.1E-1 shows the quarterly startup schedule which is based on the data presented in Table 3.1-10.

Table 3.1E-2 shows the emissions of pollutants for each quarter associated with hot start, warm start and cold starts using the startup schedule from Table 3.1-11 and the emissions for each event data from Table 3.1-15.

Total quarterly and annual emissions for each pollutant associated with startups are summarized and shown in Table 3.1E-3. Table 3.1E-4 shows the baseload and peak load quarterly emissions for each quarter for each turbine.

Tables 3.1E-5 through 3.1E-9 show the total quarterly emissions for each turbine, including startups, based load, and peak load operations. Also, the tables summarize total new emissions, including turbines, fire pump, emergency generator, auxiliary boiler and cooling tower for each pollutant.

Calculation of Maximum Hourly Emissions

a. Turbines/HRSGs

As hourly NO_x, CO and VOC emissions from the turbines are higher during startup than during peak load operation, highest hourly emissions occur while both turbines are in startup mode. Except for startup, maximum hourly emissions from the turbines occur while operating at peak load and 34 degF with power augmentation and duct firing. Emissions under this operating mode are higher than under part load or high temperature operations. Emissions under peak and base, and minimum load conditions at 99 degF, 62 degF, and 34 degF temperature conditions are shown in Appendix 3.1A.

Both turbines may be started up within the same 1 hour timeframe. Therefore highest hourly emissions from the turbines will occur when both turbines are starting up within the same 1 hour timeframe.

b. Auxiliary Boiler

Auxiliary boiler will operate in all four quarters.

c. Emergency Generator and Fire Pump

Emergency generator set and fire pump testing will not occur during turbine startups. Each test takes 30 minutes. Emergency generator will operate at 50% load during testing.

d. Cooling Tower

Maximum hourly emissions occur while the cooling tower is operating at full capacity.

Calculation of Maximum Daily Emissions

a. Turbines/HRSGs

As discussed above for the hourly emissions calculations, hourly NO_x, CO and VOC emissions are highest during startup. The operating conditions having the next highest hourly emissions are peak load operation at 34 degF with power augmentation and duct firing, followed by peak load operation at 34 degF. Therefore maximum daily turbine emissions will occur on a day when each turbine has one hot and one cold start, operates at full load with power augmentation and duct firing. Again, both turbines can be in startup mode at the same time.

b. Auxiliary Boiler

Auxiliary boiler will operate in all four quarters.

c. Emergency Generator and Fire Pump

Emergency generator set or fire pump is proposed for REP. Testing will not occur during days with startups. Each test takes 30 minutes. Emergency generator will operate at 50% load during testing.

d. Cooling Tower

Maximum daily cooling tower emissions will occur while the cooling tower is in operation for 24 hours.

Maximum Annual Emissions

a. Turbines/HRSGs

Maximum annual emissions are calculated based on the dispatch schedule of Table 3.1-10.

b. Auxiliary Boiler

Auxiliary boiler will operate in all four quarters.

c. Emergency Generator and Fire Pump

Emergency generator and fire pump will be tested 50 times per year.

Maximum Quarterly Emissions

a. Turbines/HRSGs

Quarterly turbine emission rates are calculated based on the proposed plant dispatch schedule for each quarter.

b. Auxiliary Boiler

Auxiliary boiler will operate in all four quarters.

c. Emergency Generator and Fire Pump

It is assumed that these units will be tested 12.5 times per quarter.

Table 3.1E-1. Quarterly startup schedule.[1]

	1^{st}	2^{nd}	3^{rd}	4^{th}
Number of hot starts	25	71	29	42
Hours of hot starts[1]	25	71	29	42
Number of warm starts	8	20	1	1
Hours of warm start[3]	16	40	2	2
Number of cold starts	1	2	1	1
Hours of cold starts[4]	3	6	3	3

1 – Based on Table 3.1-11.
2 – Hot start takes 1 hour.
3 – Warm start takes 2 hours.
4 – Cold start takes 3 hours.

Table 3.1E-2. Quarterly startup emissions (both turbines).[1]

	NO_X	CO	VOC	PM_{10}	SO_2
Quarter 1					
LM6000 PC Sprint					
Hot start emissions lbs/qtr	396.7	408.2	57.6	158.3	32.9
Warm start emission lbs/qtr	233.7	220.5	36.2	101.3	21.0
Cold start emission lbs/qtr	49.7	42.2	6.6	19.0	3.9
Total Quarter 1	680.2	670.9	100.5	278.6	57.9
Alstom GTX100					
Hot start emissions lbs/qtr	852.8	4,021.1	971.1	161.1	33.4
Warm start emission lbs/qtr	704.6	1,505.1	614.0	103.1	21.4
Cold start emission lbs/qtr	122.8	204.8	78.6	19.3	4.0
Total Quarter 1	1,680.3	5,731.0	1,663.7	283.5	58.9
Quarter 2					
LM6000 PC Sprint					
Hot start emissions lbs/qtr	1,126.7	1,159.4	163.7	449.6	93.4
Warm start emission lbs/qtr	584.3	551.2	90.6	253.3	52.6
Cold start emission lbs/qtr	99.5	84.3	13.2	38.0	7.9
Total Quarter 2	1,810.5	1,794.9	267.5	740.8	153.8
Alstom GTX100					
Hot start emissions lbs/qtr	2,422.0	11,420.0	2,757.8	457.5	95.0
Warm start emission lbs/qtr	1,761.6	3,762.7	1,534.9	257.7	53.5
Cold start emission lbs/qtr	245.7	409.6	157.2	38.7	8.0
Total Quarter 2	4,429.3	15,592.3	4,450.0	753.8	156.5
Quarter 3					
LM6000 PC Sprint					
Hot start emissions lbs/qtr	460.2	473.6	66.9	183.6	38.1
Warm start emission lbs/qtr	29.2	27.6	4.5	12.7	2.6
Cold start emission lbs/qtr	49.7	42.2	6.6	19.0	3.9
Total Quarter 3	539.2	543.3	78.0	215.3	44.7
Alstom GTX100					
Hot start emissions lbs/qtr	989.3	4,664.5	1,126.4	186.9	38.8
Warm start emission lbs/qtr	88.1	188.1	76.7	12.9	2.7
Cold start emission lbs/qtr	122.8	204.8	78.6	19.3	4.0
Total Quarter 3	1,200.2	5,057.4	1,281.8	219.1	45.5
Quarter 4					
LM6000 PC Sprint					
Hot start emissions lbs/qtr	666.5	685.8	96.8	265.9	55.2
Warm start emission lbs/qtr	29.2	27.6	4.5	12.7	2.6
Cold start emission lbs/qtr	49.7	42.2	6.6	19.0	3.9
Total Quarter 4	745.5	755.5	108.0	297.6	61.8
Alstom GTX100					
Hot start emissions lbs/qtr	1,432.8	6,755.5	1,631.4	270.6	56.2
Warm start emission lbs/qtr	88.1	188.1	76.7	12.9	2.7
Cold start emission lbs/qtr	122.8	204.8	78.6	19.3	4.0
Total Quarter 4	1,643.7	7,148.4	1,786.7	302.8	62.9

1 – Emissions are calculated from the number of events shown in Table 3.1-11 and the emission rates shown in Appendix 8.A.

2 – SO_2 emissions are conservatively estimated based on the highest emission rates for the turbine 50% load conditions, from Appendix 8.A.

3 – Warm start takes 2 hours.

4 – Cold start takes 3 hours.

Table 3.1E-3. Summary total quarterly and annual startup emissions for two turbines combined (pounds).[1]

	Turbine	Q1	Q2	Q3	Q4	Total
NO_X	LM6000 PC Sprint	680.2	1,810.5	539.2	745.5	3,775.3
	Alston GTX 100	1,680.3	4,429.3	1,200.2	1,643.7	8,953.5
CO	LM6000 PC Sprint	670.9	1,794.9	543.3	755.5	3,764.5
	Alston GTX 100	5,731.0	15,592.3	5,057.4	7,148.4	33,529.1
VOC	LM6000 PC Sprint	100.5	267.5	78.0	108.0	553.9
	Alston GTX 100	1,663.7	4,450.0	1,281.8	1,786.7	9,182.2
PM_{10}	LM6000 PC Sprint	278.6	740.8	215.3	297.6	1,532.3
	Alston GTX 100	283.5	753.8	219.1	302.8	1,559.2
SO_2	LM6000 PC Sprint	57.9	153.8	44.7	61.8	318.2
	Alston GTX 100	58.9	156.5	45.5	62.9	323.8

1 – This table summarizes the emissions shown in Table 3.1E-2.

Table 3.1E-10. Maximum hourly emissions, lb/hr[1].

	NO_X		SO_2[2]		CO		VOC		PM_{10}	
	LM6000	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**
2 combustion turbines/peak	10	10.2	2	2	12.2	12.5	3.5	3.6	9.2	9.5
2 combustion turbine/startup	38.7	74.2	1.3	1.3	28.7	179.0	2.9	39.4	6.3	6.4
Auxiliary Boiler	0.7	0.7	0.08	0.08	2.2	2.2	0.3	0.3	0.6	0.6
Highest	39.4	74.9	2.08	2.08	30.9	181.2	3.7	39.7	9.8	10.1
Standby generator[3]	4.48		0.094		0.84		0.16		0.13	
Fire pump[4]	1.72		0.050		0.09		0.05		0.03	
Cooling tower	--		--		--		--		0.7	
Subtotal	6.9		0.22		3.13		0.51		1.47	
Maximum hourly emissions	39.4	74.9	2.17	2.17	30.9	181.2	386	39.7	10.6	10.9

1 – Standby generator and fire pump testing do not occur during CTG startups.

2 – Maximum hourly SO_2 emissions correspond to peak load operation for the turbines and other equipment running at the same time.

3 – Emergency standby generator is only tested for 30 minutes, operating at 50% load.

4 – The fire pump testing is for 30 minutes at 100% load.

Table 3.1E-11. Maximum daily emissions, lb/day

	NO_X		SO_2		CO		VOC		PM_{10}	
	LM6000	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**
1 startup (cold)	49.7	122.8	3.9	4.0	42.2	204.8	6.6	78.6	19.0	19.3
1 startup (warm)	29.2	88.1	2.6	2.7	27.6	188.1	4.5	76.7	12.7	12.9
19 hrs peak operating	190	194.3	36.4	37.3	231.1	236.6	66.2	67.8	175.5	179.6
Subtotal	268.7	405.2	43.0	44.0	300.8	629.5	77.3	223.1	207.1	211.8
2 combustion turbine peak	239.7	245.4	46.0	47.1	291.9	298.8	83.6	85.6	221.6	226.8
Highest	268.7	405.2	46.0	47.1	300.8	629.5	83.6	223.1	221.6	226.8
Cooling tower									16.3	16.3
Emergency generator(1)	4.48		0.094		0.84		0.16		0.13	
Fire pump(1)	1.72		0.05		0.09		0.05		0.03	
Auxiliary Boiler	15.7		1.95		53.2		6.1		14.0	
Maximum daily emissions(2)	288.9	425.4	48.0	49.1	354.8.	683.5	89.9	229.4	252.4	257.6

1 – 30 minute operation for each testing period. They do not run during startup. So their emissions are not included in the maximum daily emissions, which includes startups.

2 – The highest daily emissions assumes 1 cold startups, 1 warm startups, and 19 hours of peak load operation at 34°F. It is assumed that the auxiliary boiler is also operating during that day.

Table 3.1E-12. Maximum total quarterly and annual emissions (pounds)

	NO_X		SO_2		CO		VOC		PM_{10}	
	LM6000	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**	**LM6000**	**Alstom**
Quarterly(1)	19,360.8	20,544.9	3,630.4	3,709.2	23,499.7	33,872.4	6,596.2	7,455.0	18,998.6	19,378.0
Annual	72,486.7	79,112.3	13,385.3	13,665.1	88,183.4	119,710.4	24,344.6	26,848.5	70,555.3	71,902.9

1 – Values are taken from the highest total quarterly values shown in Tables 3.1E-5 through 3.1E-9.

Roseville Energy Park

Annual Emissions - General Electric LM6000 PC SPRINT

	Quarter				Maximum Quarter	Total Annual
	1st	2nd	3rd	4th		
Combustion Turbines/HRSGs - Operating Baseload						
NOx, as NO_2, tons	3.83	4.05	2.56	2.90	4.05	13.34
CO, tons	4.66	4.93	3.12	3.54	4.93	16.24
VOC, as CH_4, tons	1.33	1.41	0.89	1.01	1.41	4.65
PM_{10}, tons	3.56	3.76	2.38	2.70	3.76	12.39
SO_2, tons	0.74	0.78	0.49	0.56	0.78	2.57
Combustion Turbines/HRSGs - Operating w/ Duct Firing						
NOx, as NO_2, tons	4.64	2.79	6.73	6.22	6.73	20.38
CO, tons	5.65	3.40	8.19	7.58	8.19	24.82
VOC, as CH_4, tons	1.62	0.97	2.35	2.17	2.35	7.11
PM_{10}, tons	4.29	2.58	6.22	5.75	6.22	18.84
SO_2, tons	0.89	0.54	1.29	1.19	1.29	3.91
Combustion Turbines/HRSGs - Hot Starts						
NOx, as NO_2, lbs	396.7	1,126.7	460.2	666.5	1,126.7	2,650.1
CO, lbs	408.2	1,159.4	473.6	685.8	1,159.4	2,727.0
VOC, as CH_4, lbs	57.6	163.7	66.9	96.8	163.7	385.0
PM_{10}, lbs	158.3	449.6	183.6	265.9	449.6	1,057.4
SO_2, lbs	32.9	93.4	38.1	55.2	93.4	219.6
Combustion Turbines/HRSGs - Warm Starts						
NOx, as NO_2, lbs	233.7	584.3	29.2	29.2	584.3	876.4
CO, lbs	220.5	551.2	27.6	27.6	551.2	826.8
VOC, as CH_4, lbs	36.2	90.6	4.5	4.5	90.6	135.9
PM_{10}, lbs	101.3	253.3	12.7	12.7	253.3	379.9
SO_2, lbs	21.0	52.6	2.6	2.6	52.6	78.9
Combustion Turbines/HRSGs - Cold Starts						
NOx, as NO_2, lbs	49.7	99.5	49.7	49.7	99.5	248.7
CO, lbs	42.2	84.3	42.2	42.2	84.3	210.8
VOC, as CH_4, lbs	6.6	13.2	6.6	6.6	13.2	33.0
PM_{10}, lbs	19.0	38.0	19.0	19.0	38.0	95.0
SO_2, lbs	3.9	7.9	3.9	3.9	7.9	19.7
Combustion Turbines/HRSGs - Starts Total						
NOx, as NO_2, lbs	680.2	1,810.5	539.2	745.5	1,810.5	3,775.3
CO, lbs	670.9	1,794.9	543.3	755.5	1,794.9	3,764.5
VOC, as CH_4, lbs	100.5	267.5	78.0	108.0	267.5	553.9
PM_{10}, lbs	278.6	740.8	215.3	297.6	740.8	1,532.3
SO_2, lbs	57.9	153.8	44.7	61.8	153.8	318.2
Combustion Turbines/HRSGs - Starts Total						

NOx, as NO_2, tons	0.34	0.91	0.27	0.37	0.91	1.89
CO, tons	0.34	0.90	0.27	0.38	0.90	1.88
VOC, as CH_4, tons	0.05	0.13	0.04	0.05	0.13	0.28
PM_{10}, tons	0.14	0.37	0.11	0.15	0.37	0.77
SO_2, tons	0.03	0.08	0.02	0.03	0.08	0.16
Combustion Turbines/HRSGs - Total						
NOx, as NO_2, tons	8.81	7.75	9.56	9.50	9.56	35.61
CO, tons	10.65	9.23	11.58	11.49	11.58	42.94
VOC, as CH_4, tons	3.00	2.52	3.28	3.24	3.28	12.04
PM_{10}, tons	7.98	6.71	8.70	8.60	8.70	32.00
SO_2, tons	1.66	1.39	1.81	1.79	1.81	6.65
Auxiliary Boiler						
NOx, as NO_2, tons	0.05	0.19	0.05	0.05	0.19	0.33
CO, tons	0.16	0.63	0.16	0.16	0.63	1.10
VOC, as CH_4, tons	0.02	0.07	0.02	0.02	0.07	0.13
PM_{10}, tons	0.04	0.17	0.04	0.04	0.17	0.29
SO_2, tons	0.01	0.02	0.01	0.01	0.02	0.04
Standby Generator						
NOx, as NO_2, tons	0.056	0.056	0.056	0.056	0.06	0.224
CO, tons	0.010	0.010	0.010	0.010	0.01	0.042
VOC, as CH_4, tons	0.002	0.002	0.002	0.002	0.00	0.008
PM_{10}, tons	0.002	0.002	0.002	0.002	0.00	0.007
SO_2, tons	0.001	0.001	0.001	0.001	0.00	0.005
Fire Pump						
NOx, as NO_2, tons	0.021	0.021	0.021	0.021	0.02	0.086
CO, tons	0.001	0.001	0.001	0.001	0.00	0.004
VOC, as CH_4, tons	0.001	0.001	0.001	0.001	0.00	0.002
PM_{10}, tons	0.000	0.000	0.000	0.000	0.00	0.001
SO_2, tons	0.001	0.001	0.001	0.001	0.00	0.002
Cooling Tower						
PM_{10}, tons	0.734	0.742	0.751	0.751	0.751	2.98
Total						
NOx, as NO_2, tons	8.93	8.01	9.68	9.62	9.68	36.24
CO, tons	10.81	9.87	11.75	11.66	11.75	44.09
VOC, as CH_4, tons	3.02	2.59	3.30	3.26	3.30	12.17
PM_{10}, tons	8.76	7.62	9.50	9.39	9.50	35.28
SO_2, tons	1.67	1.42	1.82	1.79	1.82	6.69
Total						
NOx, as NO_2, lbs	17,860.6	16,018.6	19,360.8	19,246.7	19,360.8	72,486.7
CO, lbs	21,625.2	19,736.5	23,499.7	23,321.9	23,499.7	88,183.3
VOC, as CH_4, lbs	6,046.3	5,187.7	6,596.2	6,514.5	6,596.2	24,344.6
PM_{10}, lbs	17,523.0	15,246.0	18,998.6	18,787.7	18,998.6	70,555.3
SO_2, lbs	3,330.8	2,837.5	3,630.4	3,586.6	3,630.4	13,385.3

Roseville Energy Park

Annual Emissions - Alstom GTX100

	Quarter				Maximum Quarter	Total Annual
	1st	2nd	3rd	4th		
Combustion Turbines/HRSGs - Operating Baseload						
NOx, as NO_2, tons	3.90	4.12	2.61	2.96	4.12	13.58
CO, tons	4.74	5.02	3.17	3.60	5.02	16.53
VOC, as CH_4, tons	0.41	0.43	0.27	0.31	0.43	1.42
PM_{10}, tons	3.62	3.83	2.42	2.74	3.83	12.61
SO_2, tons	0.75	0.79	0.50	0.57	0.79	2.62
Combustion Turbines/HRSGs - Operating w/ Duct Firing						
NOx, as NO_2, tons	4.75	2.86	6.89	6.37	6.89	20.87
CO, tons	5.78	3.48	8.39	7.76	8.39	25.41
VOC, as CH_4, tons	1.66	1.00	2.40	2.22	2.40	7.28
PM_{10}, tons	4.39	2.64	6.37	5.89	6.37	19.29
SO_2, tons	0.91	0.55	1.32	1.22	1.32	4.00
Combustion Turbines/HRSGs - Hot Starts						
NOx, as NO_2, lbs	852.8	2,422.0	989.3	1,432.8	2,422.0	5,696.9
CO, lbs	4,021.1	11,420.0	4,664.5	6,755.5	11,420.0	26,861.0
VOC, as CH_4, lbs	971.1	2,757.8	1,126.4	1,631.4	2,757.8	6,486.6
PM_{10}, lbs	161.1	457.5	186.9	270.6	457.5	1,076.0
SO_2, lbs	33.4	95.0	38.8	56.2	95.0	223.4
Combustion Turbines/HRSGs - Warm Starts						
NOx, as NO_2, lbs	704.6	1,761.6	88.1	88.1	1,761.6	2,642.4
CO, lbs	1,505.1	3,762.7	188.1	188.1	3,762.7	5,644.0
VOC, as CH_4, lbs	614.0	1,534.9	76.7	76.7	1,534.9	2,302.4
PM_{10}, lbs	103.1	257.7	12.9	12.9	257.7	386.6
SO_2, lbs	21.4	53.5	2.7	2.7	53.5	80.3
Combustion Turbines/HRSGs - Cold Starts						
NOx, as NO_2, lbs	122.8	245.7	122.8	122.8	245.7	614.2
CO, lbs	204.8	409.6	204.8	204.8	409.6	1,024.0
VOC, as CH_4, lbs	78.6	157.2	78.6	78.6	157.2	393.1
PM_{10}, lbs	19.3	38.7	19.3	19.3	38.7	96.6
SO_2, lbs	4.0	8.0	4.0	4.0	8.0	20.1
Combustion Turbines/HRSGs - Starts Total						
NOx, as NO_2, lbs	1,680.3	4,429.3	1,200.2	1,643.7	4,429.3	8,953.5
CO, lbs	5,731.0	15,592.3	5,057.4	7,148.4	15,592.3	33,529.1
VOC, as CH_4, lbs	1,663.7	4,450.0	1,281.8	1,786.7	4,450.0	9,182.2
PM_{10}, lbs	283.5	753.8	219.1	302.8	753.8	1,559.2
SO_2, lbs	58.9	156.5	45.5	62.9	156.5	323.8
Combustion Turbines/HRSGs - Starts						

NOx, as NO_2, tons	0.84	2.21	0.60	0.82	2.21	4.48
CO, tons	2.87	7.80	2.53	3.57	7.80	16.76
VOC, as CH_4, tons	0.83	2.22	0.64	0.89	2.22	4.59
PM_{10}, tons	0.14	0.38	0.11	0.15	0.38	0.78
SO_2, tons	0.03	0.08	0.02	0.03	0.08	0.16
Combustion Turbines/HRSGs - Total						
NOx, as NO_2, tons	9.49	9.19	10.09	10.15	10.15	38.92
CO, tons	13.39	16.30	14.09	14.93	16.30	58.71
VOC, as CH_4, tons	2.90	3.65	3.32	3.42	3.65	13.29
PM_{10}, tons	8.15	6.85	8.89	8.78	8.89	32.67
SO_2, tons	1.69	1.42	1.85	1.82	1.85	6.78
Auxiliary Boiler						
NOx, as NO_2, tons	0.05	0.19	0.05	0.05	0.19	0.33
CO, tons	0.16	0.63	0.16	0.16	0.63	1.10
VOC, as CH_4, tons	0.02	0.07	0.02	0.02	0.07	0.13
PM_{10}, tons	0.04	0.17	0.04	0.04	0.17	0.29
SO_2, tons	0.01	0.02	0.01	0.01	0.02	0.04
Standby Generator						
NOx, as NO_2, tons	0.056	0.056	0.056	0.056	0.06	0.224
CO, tons	0.010	0.010	0.010	0.010	0.01	0.042
VOC, as CH_4, tons	0.002	0.002	0.002	0.002	0.00	0.008
PM_{10}, tons	0.002	0.002	0.002	0.002	0.00	0.007
SO_2, tons	0.001	0.001	0.001	0.001	0.00	0.005
Fire Pump						
NOx, as NO_2, tons	0.021	0.021	0.021	0.021	0.02	0.086
CO, tons	0.001	0.001	0.001	0.001	0.00	0.004
VOC, as CH_4, tons	0.001	0.001	0.001	0.001	0.00	0.002
PM_{10}, tons	0.000	0.000	0.000	0.000	0.00	0.001
SO_2, tons	0.001	0.001	0.001	0.001	0.00	0.002
Cooling Tower						
PM_{10}, tons	0.73	0.74	0.75	0.75	0.75	2.98
Total						
NOx, as NO_2, tons	9.61	9.46	10.22	10.27	10.27	39.56
CO, tons	13.56	16.94	14.26	15.10	16.94	59.86
VOC, as CH_4, tons	2.92	3.73	3.34	3.44	3.73	13.42
PM_{10}, tons	8.93	7.76	9.69	9.58	9.69	35.95
SO_2, tons	1.70	1.45	1.85	1.83	1.85	6.83
Total						
NOx, as NO_2, lbs	19,218.6	18,915.4	20,433.4	20,544.9	20,544.9	79,112.3
CO, lbs	27,121.1	33,872.4	28,515.1	30,201.8	33,872.4	119,710.4
VOC, as CH_4, lbs	5,832.3	7,455.0	6,671.6	6,889.7	7,455.0	26,848.5
PM_{10}, lbs	17,854.4	15,512.5	19,378.0	19,157.9	19,378.0	71,902.9
SO_2, lbs	3,399.6	2,892.9	3,709.2	3,663.4	3,709.2	13,665.1

APPENDIX D

PCAPCD EMISSION CALCULATIONS

PCAPCD Emission Calculations
Alstom Turbines

BASE	lbs/hr per turbine	lbs/hr two turbines	Hours/turbine Quarter 1	Hours/turbine Quarter 2	Hours/turbine Quarter 3	Hours/turbine Quarter 4
NO_x	3.469	6.938	1,123	1,188	751	852
CO	4.224	8.448	1,123	1,188	751	852
VOC	0.363	0.730	1,123	1,188	751	852
PM_{10}	3.222	6.444	1,123	1,188	751	852
SO_2	0.669	1.338	1,123	1,188	751	852

PEAK	lbs/hr per turbine	lbs/hr two turbines	Hours/turbine Quarter 1	Hours/turbine Quarter 2	Hours/turbine Quarter 3	Hours/turbine Quarter 4
NO_x	5.133	10.266	929	559	1,347	1,246
CO	6.226	12.452	929	559	1,347	1,246
VOC	1.783	3.566	929	559	1,347	1,246
PM_{10}	4.726	9.452	929	559	1,347	1,246
SO_2	0.981	1.962	929	559	1,347	1,246

HOT START	Pounds Per Start - one turbine	Pounds Per Start - two turbines	Hot Starts Quarter 1	Hot Starts Quarter 2	Hot Starts Quarter 3	Hot Starts Quarter 4
NO_x	22.6	34.1	25	71	29	42
CO	83.5	160.8	25	71	29	42
VOC	19.6	38.8	25	71	29	42
PM_{10}	3.2	6.4	25	71	29	42
SO_2	0.7	1.3	25	71	29	42

WARM START	Pounds Per Start - one turbine	Pounds Per Start - two turbines	Warm Starts Quarter 1	Warm Starts Quarter 2	Warm Starts Quarter 3	Warm Starts Quarter 4
NO_x	37.1	88.1	8	20	1	1
CO	89.5	188.1	8	20	1	1
VOC	19.7	76.7	8	20	1	1
PM_{10}	3.2	12.9	8	20	1	1
SO_2	0.7	2.7	8	20	1	1

COLD START	Pounds Per Start - one turbine	Pounds Per Start - two turbines	Cold Starts Quarter 1	Cold Starts Quarter 2	Cold Starts Quarter 3	Cold Starts Quarter 4
NO_x	37.1	122.8	1	2	1	1
CO	89.5	204.8	1	2	1	1
VOC	19.7	78.6	1	2	1	1
PM_{10}	3.2	19.3	1	2	1	1
SO_2	0.7	4	1	2	1	1

PCAPCD Emission Calculations
Alstom Turbines

BASE	Two Turbine Base Quarter 2 Lbs/quarter	Two Turbine Base Quarter 2 Lbs/quarter	Two Turbine Base Quarter 3 Lbs/quarter	Two Turbine Base Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	7,791	8,242	5,210	5,911	13.58
CO	9,487	10,036	6,344	7,198	16.53
VOC	820	867	548	622	1.43
PM_{10}	7,237	7,655	4,839	5,490	12.61
SO_2	1,503	1,590	1,005	1,140	2.62

PEAK	Two Turbine Peak Quarter 1 Lbs/quarter	Two Turbine Peak Quarter 2 Lbs/quarter	Two Turbine Peak Quarter 3 Lbs/quarter	Two Turbine Peak Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	9,537	5,739	13,828	12,791	20.95
CO	11,568	6,961	16,773	15,515	25.41
VOC	3,313	1,993	4,803	4,443	7.28
PM_{10}	8,781	5,284	12,732	11,777	19.29
SO_2	1,823	1,097	2,643	2,445	4.00

HOT START	Two Turbine Hot Start Quarter 1 Lbs/quarter	Two Turbine Hot Start Quarter 2 Lbs/quarter	Two Turbine Hot Start Quarter 3 Lbs/quarter	Two Turbine Hot Start Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	853	2,421	989	1,432	2.85
CO	4,020	11,417	4,663	6,754	13.43
VOC	970	2,755	1,125	1,630	3.24
PM_{10}	160	454	186	269	0.53
SO_2	33	92	38	55	0.11

WARM START	Two Turbine Warm Start Quarter 1 Lbs/quarter	Two Turbine Warm Start Quarter 2 Lbs/quarter	Two Turbine Warm Start Quarter 3 Lbs/quarter	Two Turbine Warm Start Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	705	1,762	88	88	1.32
CO	1,505	3,762	188	188	2.82
VOC	614	1,534	77	77	1.15
PM_{10}	103	258	13	13	0.19
SO_2	22	54	3	3	0.04

COLD START	Two Turbine Cold Start Quarter 1 Lbs/quarter	Two Turbine Cold start Quarter 2 Lbs/quarter	Two Turbine Cold Start Quarter 3 Lbs/quarter	Two Turbine Cold Start Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	123	246	123	123	0.31
CO	205	410	205	205	0.51
VOC	79	157	79	79	0.20
PM_{10}	19	39	19	19	0.05
SO_2	4	8	4	4	0.01

STARTUP SUBTOTAL	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	1,680	4,429	1,200	1,643	4.48
CO	5,730	15,588	5,056	7,147	16.76
VOC	1,662	4,446	1,281	1,785	4.59
PM_{10}	283	751	218	301	0.78
SO_2	58	154	44	61	0.16

TURBINE TOTAL	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	19,009	18,410	20,239	20,346	39.00
CO	26,785	32,585	28,173	29,859	58.70
VOC	5,795	7,307	6,632	6,850	13.29
PM_{10}	16,300	13,690	17,789	17,568	32.67
SO_2	3,383	2,841	3,692	3,646	6.78

PCAPCD Emission Calculations

Alstom Turbines	lbs/hr	lbs/day		Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx				9.50	9.20	10.12	10.17	39.00
CO				13.39	16.29	14.09	14.93	58.70
VOC				2.90	3.65	3.32	3.43	13.29
PM10				8.15	6.85	8.89	8.78	32.67
SO2				1.69	1.42	1.85	1.82	6.78

Boiler	lbs/hr	lbs/day	BOILER	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx	0.7	16.8		0.05	0.19	0.05	0.05	0.34
CO	2.2	52.8		0.16	0.65	0.16	0.16	1.14
VOC	0.3	7.2		0.02	0.09	0.02	0.02	0.15
PM10	0.9	21.6		0.04	0.16	0.04	0.04	0.29
SO2	0.08	1.92		0.01	0.02	0.01	0.01	0.04

Cooling Tower	lbs/hr	lbs/day		Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx	-	-	-	0.00	0.00	0.00	0.00	0.00
CO	-	-	-	0.00	0.00	0.00	0.00	0.00
VOC	-	-	-	0.00	0.00	0.00	0.00	0.00
PM10	0.681	16.34579		0.74	0.74	0.75	0.75	2.98
SO2	-	-	-	0.00	0.00	0.00	0.00	0.00

TOTAL EMISSIONS - Boiler,Alstom Turbines, Cooling Tower				Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx				9.55	9.40	10.17	10.22	39.34
CO				13.55	16.94	14.25	15.09	59.84
VOC				2.92	3.74	3.34	3.45	13.45
PM10				8.93	7.75	9.69	9.58	35.95
SO2				1.70	1.44	1.85	1.83	6.82

Emergency Generator (Caterpilla			1133 hp					
	g/hp-hr	lbs/hr	lbs/day max	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx	6.9	8.62	206.8	0.027	0.027	0.027	0.027	0.108
CO	1.34	1.67	40.2	0.005	0.005	0.005	0.005	0.021
VOC	0.25	0.31	7.5	0.001	0.001	0.001	0.001	0.004
PM10	0.22	0.27	6.6	0.001	0.001	0.001	0.001	0.003
SO2	-	0.19	4.6	0.001	0.001	0.001	0.001	0.002
Assuming 30 minutes per week testing (6.5 hours/quarter) and total of 50 hrs per year max at 50% load.								
Quarterly emissions calculated based on 12.5 hours per quarter at half load.								

Fire Pump			300.0 hp					
	g/hp-hr	lbs/hr	bs/day ma	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx	5.2	3.44	82.5	0.011	0.011	0.011	0.011	0.043
CO	0.27	0.18	4.3	0.001	0.001	0.001	0.001	0.002
VOC	0.15	0.10	2.4	0.000	0.000	0.000	0.000	0.001
PM10	0.09	0.06	1.4	0.000	0.000	0.000	0.000	0.001
SO2	0.099	0.38	9.1	0.001	0.001	0.001	0.001	0.005
Assuming 30 minutes per week testing (6.5 hours/quarter) and total of 50 hrs per year max at 50% load.								
Quarterly emissions calculated based on 12.5 hours per quarter at maximum load.								

Total Facility - Alstom Turbines								
				Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx				19,266	18,995	20,447	20,567	39.64
CO				27,014	33,772	28,405	30,091	59.64
VOC				5,874	7,501	6,726	6,941	13.52
PM10				17,804	15,612	19,323	19,103	35.92
SO2				3,507	2,988	3,808	3,765	7.03

PCAPCD Emission Calculations
GE LM6000 Turbines

BASE	Lbs/quarter per turbine Quarter 1	Lbs/quarter per turbine Quarter 2	Lbs/quarter per turbine Quarter 3	Lbs/quarter per turbine Quarter 4
NO_x	3,827	4,049	2,559	2,904
CO	4,660	4,930	3,117	3,536
VOC	1,334	1,411	892	1,012
PM_{10}	3,555	3,761	2,378	2,697
SO_2	738	781	493	560

PEAK	Lbs/quarter per turbine Quarter 1	Lbs/quarter per turbine Quarter 2	Lbs/quarter per turbine Quarter 3	Lbs/quarter per turbine Quarter 4
NO_x	4,639	2,792	6,727	6,223
CO	5,649	3,399	8,191	7,577
VOC	1,618	974	2,346	2,171
PM_{10}	4,289	2,581	6,219	5,753
SO_2	891	536	1,292	1,195

HOT START	Lbs/quarter per turbine Quarter 1	Lbs/quarter per turbine Quarter 2	Lbs/quarter per turbine Quarter 3	Lbs/quarter per turbine Quarter 4
NO_x	220	625	255	370
CO	230	653	267	386
VOC	35	99	41	59
PM_{10}	80	227	93	134
SO_2	18	50	20	29

WARM START	Lbs/quarter per turbine Quarter 1	Lbs/quarter per turbine Quarter 2	Lbs/quarter per turbine Quarter 3	Lbs/quarter per turbine Quarter 4
NO_x	98	244	12	12
CO	86	216	11	11
VOC	11	28	1	1
PM_{10}	26	64	3	3
SO_2	6	14	1	1

COLD START	Lbs/quarter per turbine Quarter 1	Lbs/quarter per turbine Quarter 2	Lbs/quarter per turbine Quarter 3	Lbs/quarter per turbine Quarter 4
NO_x	19	39	19	19
CO	14	29	14	14
VOC	1	3	1	1
PM_{10}	3	6	3	3
SO_2	1	1	1	1

PCAPCD Emission Calculations
GE LM6000 Turbines

BASE	Two Turbine Base Quarter 1 Lbs/quarter	Two Turbine Base Quarter 2 Lbs/quarter	Two Turbine Base Quarter 3 Lbs/quarter	Two Turbine Base Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	7,654	8,097	5,119	5,807	13.34
CO	9,321	9,860	6,233	7,072	16.24
VOC	2,668	2,823	1,784	2,024	4.65
PM_{10}	7,111	7,522	4,755	5,395	12.39
SO_2	1,476	1,561	987	1,120	2.57

PEAK	Two Turbine Peak Quarter 1 Lbs/quarter	Two Turbine Peak Quarter 2 Lbs/quarter	Two Turbine Peak Quarter 3 Lbs/quarter	Two Turbine Peak Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	9,279	5,583	13,454	12,445	20.38
CO	11,298	6,799	16,382	15,154	24.82
VOC	3,237	1,948	4,693	4,341	7.11
PM_{10}	8,578	5,162	12,438	11,506	18.84
SO_2	1,782	1,072	2,584	2,390	3.91

HOT START	Two Turbine Hot Start Quarter 1 Lbs/quarter	Two Turbine Hot Start Quarter 2 Lbs/quarter	Two Turbine Hot Start Quarter 3 Lbs/quarter	Two Turbine Hot Start Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	398	1,129	461	668	1.33
CO	408	1,157	473	685	1.36
VOC	58	163	67	97	0.19
PM_{10}	158	447	183	265	0.53
SO_2	33	92	38	55	0.11

WARM START	Two Turbine Warm Start Quarter 1 Lbs/quarter	Two Turbine Warm Start Quarter 2 Lbs/quarter	Two Turbine Warm Start Quarter 3 Lbs/quarter	Two Turbine Warm Start Quarter 4 Lbs/quarter	Annual (Tpy)
NO_x	234	584	29	29	0.44
CO	221	552	28	28	0.41
VOC	36	90	5	5	0.07
PM_{10}	102	254	13	13	0.19
SO_2	21	52	3	3	0.04

COLD START	Two Turbine Cold Start Quarter 1 Lbs/quarter	Two Turbine Cold start Quarter 2 Lbs/quarter	Two Turbine Cold Start Quarter 3 Lbs/quarter	Two Turbine Cold Start Quarter 4 Lbs/quarter	
NO_x	50	99	50	50	0.12
CO	42	84	42	42	0.11
VOC	7	13	7	7	0.02
PM_{10}	19	38	19	19	0.05
SO_2	4	8	4	4	0.01

STARTUP SUBTOTAL	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	681	1,812	540	747	1.89
CO	671	1,794	543	754	1.88
VOC	100	267	78	108	0.28
PM_{10}	278	739	214	296	0.76
SO_2	57	152	44	61	0.16

TURBINE TOTAL	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	17,614	15,493	19,113	18,999	35.61
CO	21,290	18,453	23,158	22,980	42.94
VOC	6,005	5,037	6,555	6,473	12.03
PM_{10}	15,967	13,424	17,408	17,197	32.00
SO_2	3,315	2,785	3,615	3,570	6.64

PCAPCD Emission Calculations

GE Turbines	lbs/hr	lbs/day				Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x						17,614	15,493	19,113	18,999	35.61
CO						21,290	18,453	23,158	22,980	42.94
VOC						6,005	5,037	6,555	6,473	12.03
PM_{10}						15,967	13,424	17,408	17,197	32.00
SO_2						3,315	2,785	3,615	3,570	6.64

BOILER	lbs/hr	lbs/day				Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	0.68	16.3				95	386	97	97	0.34
CO	2.29	55.0				321	1301	327	327	1.14
VOC	0.31	7.5				44	177	44	44	0.15
PM_{10}	0.58	13.9				81	329	83	83	0.29
SO_2	0.08	1.9				11	45	11	11	0.04

Cooling Tower	lbs/hr	lbs/day				Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	-	-	-							
CO	-	-	-							
VOC	-	-	-							
PM_{10}	0.681	16.35				1,471	1,487	1,504	1,504	2.98
SO_2	-	-	-							

TOTAL EMISSIONS - Boiler,GE Turbines, Cooling Tower						Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NOx						17,709	15,879	19,210	19,096	35.95
CO						21,610	19,753	23,485	23,307	44.08
VOC						6,049	5,213	6,600	6,518	12.19
PM_{10}						17,520	15,240	18,995	18,783	35.27
SO_2						3,326	2,831	3,626	3,582	6.68

Emergency Generator (Caterpillar ,		1133 hp								
	g/hp-hr	lbs/hr	lbs/day max			Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	6.9	4.31	4.31			54	54	54	54	0.108
CO	1.34	0.84	0.84			10	10	10	10	0.021
VOC	0.25	0.16	0.16			2	2	2	2	0.004
PM_{10}	0.22	0.14	0.14			2	2	2	2	0.003
SO_2	-	0.10	0.10			1	1	1	1	0.002
Assuming 30 minutes per week testing (6.5 hours/quarter) and total of 50 hrs per year max at 50% load. Daily maximum calculated 30 minutes testing.										
Quarterly emissions calculated based on 12.5 hours per quarter.										

Fire Pump			300.0 hp							
	g/hp-hr	lbs/hr	lbs/day max			Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x	5.2	1.72	1.72			43	43	43	43	0.086
CO	0.27	0.09	0.09			2	2	2	2	0.004
VOC	0.15	0.05	0.05			1	1	1	1	0.002
PM_{10}	0.09	0.03	0.03			1	1	1	1	0.001
SO_2	0.099	0.19	0.19			5	5	5	5	0.010
Assuming 30 minutes per week testing (6.5 hours/quarter) and total of 50 hrs per year max at 50% load. Daily maximum calculated also based on 30 minutes of										
Quarterly emissions calculated based on 12.5 hours per quarter.										

Total Facility - GE LM6000 Turbines										
						Quarter 1	Quarter 2	Quarter 3	Quarter 4	Annual (Tpy)
NO_x						17,806	15,976	19,307	19,193	36.14
CO						21,623	19,766	23,498	23,320	44.10
VOC						6,052	5,217	6,603	6,521	12.20
PM_{10}						17,522	15,243	18,997	18,786	35.27
SO_2						3,332	2,837	3,632	3,588	6.69

PCAPCD Boiler Emission Calculations

Fuel

	Density (lbs/scf)	Btu/lb	Btu/scf
Natural Gas	0.045	22,794	1,026

Boiler Rating

58 MMBtu/hr
56,530 scf per hour

NOx Calculations (Enter number in cell with blue text)

ppm =	9.24	measured
acfm=	16709.6	
Mosture Content	16.66%	
dscfm=dry standard cubic feet per minute=	10,063	

SV = specific molar volume = 379.5 @ 60 degrees F
Qsd = flowrate dscfm
MW = NOx = 46

NOx lbs/hr = ppm x 10^-06[MW]/SV x Qsd x 60 lbs/day
Max $\boxed{0.68 \quad .}$

CO Calculations (Enter number in cell with blue text)

ppm @3%O2 =	50	
ppm =	51.31	measured
acfm=	16709.6	
Mosture Content	16.66%	
dscfm=dry standard cubic feet per minute=	10,063	

SV = specific molar volume = 379.5 @ 60 degrees F
Qsd = flowrate dscfm
MW = CO = 28

CO lbs/hr = ppm x 10^-06[MW]/SV x Qsd x 60 lbs/day
Max $\boxed{2.29}$

VOC Calculations

Emission Factor (lbs/MMscf)	MMscf/hr	lbs/hr
5.5	0.056530214	0.311

PM-10 Calculations

District Calculations using AP-42	Emission Factor (lbs/MMscf)*	MMscf/hr	lbs/hr
	7.6	0.0565302	0.430

* AP-42 (7/98) Table 1.4-2 Emission Factors for Criteria Pollutants and Greenhouse gases from natural gas combustion

Applicant indicates the boiler PM-10 emissions will be 0.01 lbs/MMBtu. At 58 MMBtu/hr, PM-10 emission are calculated by multiplying 58 x 0.01. This equals 0.58 lbs/hr of PM-10.

SOx-10 Calculations

Emission Factor (lbs/MMscf)

0.6 for gas with 20 grains per 100 cf*
1.5 for natural gas with 50 grains/100 cf

* AP-42 (7/98) Table 1.4-2 Emission Factors for Criteria Pollutants and Greenhouse gases from natural gas combustion; assumes 100% of fuel sulfur is converted to SO2

Emission Factor (lbs/MMscf)	MMscf/hr	lbs/hr
1.5	0.0565	0.08

	Max/day	Quarter 1	Quarter 2	Quarter 3	Quarter 4	Hours/year
Operating hours	24	140	568	143	143	995

Boiler								
	lbs/hr	lbs/day max		Quarter 1 lbs	Quarter 2 lbs	Quarter 3 lbs	Quarter 4 lbs	Annual (Tpy)
NOx	0.68	16.3		95	386	97	97	0.34
CO	2.29	55.0		321	1,301	327	327	1.14
VOC	0.31	7.5		44	177	44	44	0.15
PM10	0.58	13.9		81	329	83	83	0.29
SO2	0.08	1.9		11	45	11	11	0.04

Fuel

	Density (lbs/scf)	Btu/lb	Btu/scf
Natural Gas	0.045	22,794	1,026

Boiler Rating

58 MMBtu/hr
56,530 scf per hour

APPENDIX E
INTERPOLLUTANT OFFSET
VOCs for NOx

ATMOSPHERIC DYNAMICS
METEOROLOGICAL AND AIR QUALITY MODELING

May 6, 2004

John Finnell
Sr. Air Pollution Control Engineer
Placer County APCD
11464 B Avenue
DeWitt Center
Auburn, Ca. 95603

Subject: Roseville Energy Park VOC or NO_x Interpollutant Trading Ratio

Dear Mr. Finnell;

Roseville Electric (RE) is proposing to use VOC emission reduction credits to offset a portion of their NO_x emissions from the proposed Roseville Energy Park (REP). They are proposing a 2.6:1 interpollutant offset ratio that, when applied to the Placer County APCD distance ratio of 2.0, results in a final ratio of 5.2:1. The proposed use of the 2.6:1 offset ratio is based upon review of the SMUD Cosumnes Power Project (CPP) interpollutant trade analysis, dated October 21, 2002. CPP performed a wide variety of analyses, including the use of the UAM model, to determine a VOC/NO_x offset ratio. These results of the UAM modeling are summarized in the October 21, 2002 Final Determination of Compliance. These studies indicate that a large degree of uncertainty exists with each method used to calculate interpollutant offset ratios. The UAM results provide a range of offset ratios between 0.6 and 7.9 with an average VOC/NO_x ratio of 2.0:1. To account for model uncertainty, an additional factor of 30% was applied to the average VOC/NO_x ratio to produce a final ratio of 2.6:1. REP proposes to use the same conservative 2.6:1 VOC/NO_x ratio rather than performing new UAM analyses that would ultimately produce a similar range of uncertainties. Furthermore, it is RE's position that the regional climate of the greater Sacramento area controls the generation of ozone.

Ozone formation depends on many factors but in the Sacramento area, the two most important factors are mobile emissions and weather conditions. Although changes in regional daily emissions of ozone precursors (such as automobile emissions) can affect daily ozone concentrations, weather variations best explain the day-to-day changes in ozone concentrations in this region. Understanding how weather influences ozone concentrations is critical in accurately predicting high ozone concentrations.

ATMOSPHERIC DYNAMICS

RE's proposal to use the CPP UAM study in order to apply the 2.6:1 interpollutant offset ratio is based on the fact that similar meteorological patterns exist between the REP and CPP sites that produce high ozone days. The proposed REP and CPP project sites are both situated in a transition zone between the Sierra Nevada Mountains and the Central Valley of California, within the Sacramento Valley. In this area, broad alluvial fans extend from the Sierra Nevada Mountains in the east toward sedimentary deposits in the Sacramento Valley to the west. A regional location map is shown in the attached figure that also includes the location of the CPP project in relation to REP.

The terrain in the vicinity of REP and CPP is characterized as generally flat with rolling foothills and the Sierra Nevada Mountains to the east, and the Sacramento Valley extending to the north, west and south. The terrain elevation on the REP plant site is approximately 95 feet above mean sea level (amsl). The proposed REP project is located in Placer County, in the southern part of the Sacramento Valley Air Basin while the CPP project site is located in South Sacramento County at an elevation of 160 feet (amsl). The overall terrain in the vicinity of both projects slopes gently downward in a westward direction toward the Sacramento Valley. At present, the area surrounding the site is generally undeveloped with some agricultural land uses.

The overall climate of California and including the REP and CPP project areas is "Mediterranean," with overall moderate annual temperatures and precipitation occurring primarily during the winter months. The meteorology is dominated by a semi-permanent high-pressure system over the eastern Pacific Ocean off the coast of California. The center of the high-pressure system varies northward and southward. Its position strongly influences the weather in the region.

Given the large spatial variation of the primary emissions within the greater Sacramento area, it is the local regional climate that fosters generation of ozone. Meteorology is the dominant factor controlling the change in ozone air quality from one day to the next. Synoptic and mesoscale meteorological features govern the transport of emissions between sources and receptors, affecting the dilution and dispersion of pollutants during transport and the time available during which pollutants can react with one another to form ozone. These features are important to transport studies and modeling efforts owing to their influence on reactive components and ozone formation and deposition.

The summer climatology of central California is generally dominated by the semi-permanent Eastern Pacific High-Pressure System. This synoptic feature is manifest as a dome of warm air (a maximum in the 500-mb geopotential height field) with a surrounding anticyclonic circulation (clockwise in the Northern Hemisphere). Therefore, surface winds blow clockwise and outward from the high, a motion associated with low-level divergence, and therefore sinking motion aloft and fair weather. This sinking motion also gives rise to adiabatic heating and therefore warm temperatures aloft. A key indicator of this warm, capping subsidence inversion in California is the temperature of the 850-mb pressure surface from the Oakland soundings. This single meteorological variable from the 0400 PST sounding is perhaps best correlated with surface ozone concentrations in the central valley (e.g., Smith et al. 1984; Smith 1994; Fairley and De Mandel 1996, Ship and McIntosh

1999). The shape of the 500-mb height contours (at 5500-m elevation) over the Eastern Pacific is broad and flat and can extend inland for hundreds of kilometers.

Accompanying the warm temperatures aloft, are warm temperatures on the central valley floor. The coastal cities of San Francisco and Santa Maria have mean daily maximum temperatures in the low- to mid-70s (deg F) while Sacramento averages about 20 F warmer. The northern and southern ends of the Central Valley, represented by Redding and Bakersfield, average an additional 5 F warmer than Sacramento. This heating causes an inland thermal low pressure trough as evidenced by the lower station pressures at Redding and Bakersfield. The pressure gradient enhances the movement of the thermally generated sea breeze through the Carquinez Straight, through other gaps in the coastal range to the north and south of the San Francisco Bay, and sometimes over the coastal range altogether. Pollutants from the San Francisco Bay Area source region are carried with the breeze to receptor regions within the Central Valley. With the abundant sunlight accompanying this weather pattern, the transported pollutants and the Sacramento Valley and San Joaquin Valley emissions cause frequent exceedances of the 1hr and 8hr standards at several sites in the interior of the Central Valley.

This typical scenario is observed on most summer afternoons. For the San Francisco Bay Area, Hayes et al. (1984) assign a frequency of 77% to sea breeze conditions matching average surface wind streamlines at 1600 PST. They give a frequency of 75% for the Sacramento Valley. However, the high pressure system can migrate with changes in the planetary weather pattern. The center of the pressure cell can move ashore, causing a decrease and even a reversal in the mean pressure gradients (Pun et al. 1998). The sea breeze is weakened, and its inland extent can become limited, leading to stagnation conditions fostering higher ozone concentrations in many areas. The high can also move east all together, followed by a trough that ventilates the valley. The high pressure is not always dominant. Neff et al. (1994) classified synoptic patterns during summer 1994 and found approximately one-third of the days to be "normal" Pacific highs, one-third to be inland highs, and one-third to be troughs. Therefore, the mesoscale sea breeze surface pattern, with 77% frequency, must exist in more than one synoptic regime. Mesoscale features must be considered in any discussion of ozone climatology. Several mesoscale flow features in Central California can have significant air quality impacts by transporting or blocking transport of ozone and precursors between important source/receptor couples. These are discussed below.

<u>The Sea Breeze and Marine Air Intrusion</u>

Differential heating between the land and ocean causes a pressure gradient between the relatively cooler denser air over ocean and the warmer air over the land. The marine air mass comes ashore. However, this heating takes time to occur and may be impeded if a cloud cover prevents direct insolation of the land. A further complication may be provided by any additional surface pressure gradients due to synoptic conditions that can enhance, hinder, or overwhelm this thermal effect. The actual time of onset of a sea breeze can be difficult to forecast with overnight fog or coastal status. Typically, with calm coastal mornings, rush hour pollutants can accumulate in the coastal source region. Then, as the sea breeze is established (often by late-morning, usually by mid-day), maximum ozone production can occur after pollutants leave the coastal areas. It is well-known that maximum ozone occurs downwind of respective source areas (e.g., Livermore downwind of the San Francisco Bay communities.) As marine air penetrates the mainland, it is modified and can become entrained in a different thermal flow, e.g., an upvalley or upslope flow. Studies of sea breeze and marine air intrusion impacts on Central California air quality include that by Stoeckenius et al, (1994), who present an objective classification scheme.

Nocturnal Jets and Eddies

A low-level nocturnal wind maximum can arise as the nocturnal inversion forms and effectively reduces boundary layer friction. Wind friction can be represented as a force that is directly opposed to the wind (termed the "antitriptic wind" by Schaefer and Doswell 1980). The overall direction of flow is determined by the vector balance among horizontal pressure gradient, Coriolis, and frictional forces. However, in the evening, with the establishment of a surface-based nocturnal inversion, the friction is "turned off." The flow is no longer in balance, and there is a component of the pressure gradient force that is directed along the wind, increasing wind speed, which increases the Coriolis force. Since Coriolis force is always 90° to the right of the wind (in the northern hemisphere), this means that the wind must veer. In the San Joaquin Valley, the rapidly moving jet (7-30 m/s) may veer toward the western valley but is channeled by the topography and soon encounters the Tehachapi range. While the nocturnal jet may be present in other seasons, it has been observed during the ozone season (Smith et al. 1981). It is believed to be a transport mechanism during the summer months. Depending on the temperature structure of the valley, the jet may not be able to exit through Tehachapi Pass (~1400 meters), as it can during the neutral stability of daytime convective heating. The air is forced to turn north along the Sierra foothills at the southeastern edge of the San Joaquin Valley. During the Southern San Joaquin Ozone Study, Blumenthal et al. (1985) measured the Fresno eddy extending above 900 meters amsl about 50% of the time. The impact of these jets and eddies is to redistribute pollutants within an air basin. The San Joaquin Valley nocturnal jet can bring pollutants from the north part of the valley to the south overnight. Ozone created in the south San Joaquin Valley can then be redistributed to the central San Joaquin Valley and/or can be transported into layers aloft by the eddy. The Schultz eddy forms when westerly marine air flow in the south San Joaquin Valley (which may become a jet with the evening boundary layer) impacts the Sierra and turns north. It can redistribute pollutants to Sutter Buttes and points north and east (or west after a half-circulation) of Sacramento (Schultz, 1975; ARB, 1989).

Upslope/Downslope Flow

The increased daytime heating in mountain canyons and valleys with a topographic amplification factor (i.e., heating less air volume when compared to flat land; see White, 1991) causes significant upslope flows during the afternoons in the San Joaquin and Sacramento Valleys. This can act as a removal mechanism, and can lift mixing heights on edges of the valleys, relative to the mixing heights at valley center. Myrup et al. (1989) studied transport of aerosols from the San Joaquin valley into Sequoia National Park. They found a net up flow of most species. The return flow can bring pollutants back down. Smith et al. (1981) from tracer mass budgets during tracer releases has estimated pollutant budgets due to slope flow fluxes (and other ventilation mechanisms). Smith et al. caution that less polluted air at higher elevations is entrained in the slope flow, thus diluting San Joaquin Valley air and removing less pollutants. From the tracer mass balance, they found that northwesterly flow was a more effective dilution mechanism, and the benefits of slope flow removal by upslope flows would be confined to the edges of the valley.

Up-Valley/Down-Valley Flow

Up-valley flow draws air south in the San Joaquin Valley and north in the Sacramento Valley during the day, while down-valley drainage winds tend to ventilate both valleys at night.

Conclusion

The spatial pattern of ozone exceedances is associated with the frequency of particular meteorological conditions that affect transport of pollutants from the major urban centers (i.e., San Francisco Bay Area and Sacramento) to the San Joaquin Valley, Sacramento Valley and to the Mountain Counties. This analysis showed the importance of the sea breeze in determining spatial distribution of ozone accumulation. When the sea breeze is inhibited, higher ozone levels occur throughout the region. In addition, it demonstrates that ozone impacts in the Sacramento area are caused by regional meteorological conditions that exist over large length scales. Thus, regional ozone impacts are a direct consequence of the mesoscale meteorological patterns that exist in region, rather than the specific location of sources of NO_x and VOCs. Both the CPP and REP are located in similar atmospheric and surface geological terrains and thus are subjected to similar meteorological conditions.

The CPP UAM modeling domain included these same meteorological parameters that would simulate the mesoscale patterns that are the driving force in producing high ozone days. Since these mesoscale parameters are of sufficient length scales to incorporate the REP and CPP impact areas, the CPP UAM modeling is applicable to the REP project. With the relatively close proximity of REP to CPP and given that the meteorological modeling domain is of sufficient length scale, review of the CPP UAM modeling analysis shows that the same regional meteorological patterns input into UAM would exist over the Placer County Air Basin, thus, making the existing UAM modeling study applicable to REP in terms of magnitude and scope.

With the application of the Placer County APCD 2.0 distance ratio, which also accounts for the spatial separation of sources, to the 2.6:1 VOC/NO_x ratio from CPP, the resulting offset ratio is 5.2:1. Therefore, based on the fact that regional meteorology is the driving force in producing high ozone concentrations and that the same mesoscale meteorological conditions exist at both the CCP and REP sites, REP proposes to use an overall VOC to NO_x ratio of 5.2:1 for currently identified VOC to NOx conversions. T his VOC/NO_x ratio would produce the highest offset ratio used for any power plants in the state.

If you have any questions or comments, please do not hesitate to call me at (805) 569-6555.

Sincerely,

ATMOSPHERIC DYNAMICS, INC.

Gregory Darvin

Gregory Darvin

APPENDIX F

Letters Regarding Offsets

Enron North America Corp.
P.O. Box 1188
Houston, TX 77251-1188

February 25, 2004

Mr. Tom Habashi
Electric Utility Director
City of Roseville
2090 Hilltop Circle
Roseville, California 95747

Re: Purchase and Sale of Emission Reduction Credits

Dear Mr. Habashi:

Pursuant to your request, this letter confirms that Enron North America Corporation ("Enron") and the City of Roseville ("Roseville") recently executed a Purchase and Sale Agreement dated as of February 13, 2004 (the "Agreement") for the purchase and sale of certain emission reduction credits ("ERC's"). As of the date of the Agreement, and subject to the terms and conditions set forth in said Agreement, Enron agrees to sell and Roseville undertakes to buy the following ERC's:

Placer County Air Pollution Control District Certificate #	Pollutant	Quantity (tons/year)
2001-23	NOx	10.1
2002-26	VOC	67.0
2001-22	PM10	28.4
2001-24	PM10	29.4

Should you have any questions or concerns regarding the above, please do not hesitate to contact Scott Churbock at 713-345-4623.

Sincerely,

Charles E. Schneider RMP
Managing Director

Roseville Electric
Reliable Energy • Dependable Service

2090 Hilltop Circle
Roseville, CA 95747
Office (916) 774-5600
FAX (916) 784-3797
TDD (916) 774-5220
www.RosevilleElectric.org

May 4, 2004

Mr. Tom Christofk
Air Pollution Control Officer
Placer County Air Pollution Control District
11464 B Avenue
Dewitt Center
Auburn, CA 95603

Subject: ***Roseville Energy Park***
Disclosure of Confidential Emission Reductions

Dear Mr. Christofk,

Roseville Electric has been diligently pursuing securing emission reductions for use as offsets for the Roseville Energy Park (REP). We had previously submitted information to Placer County Air Pollution Control District (District) to support your analysis and preparation of the Determination of Compliance (DOC). Some of the information previously submitted identified holders of Emission Reduction Credits (ERCs) and owners of facilities that may create new ERCs with whom Roseville Electric was negotiating. The District agreed to treat this information as confidential pursuant to state and federal law. At this time, Roseville Electric has concluded negotiations with two emission reduction sources. Since these negotiations have concluded, the District would no longer have to treat the information about these two sources as confidential. We are currently negotiating with others to obtain additional emission reductions and therefore request that the District continue to treat any information previously submitted, other than information relating to the two sources outlined in the attachment to this letter as confidential.

Sincerely,

Robert Hren

Robert Hren
REP Project Manager

CITY OF ROSEVILLE
TRADITION • PRIDE • PROGRESS

Attachment to letter, R. Hren to T. Christofk dated 5-4-04

Roseville Energy Park
Additional NOx ERC's

I. Existing ERC's. Roseville Electric and the City of Roseville have concluded negotiations for the following NOx emission reduction credits (ERC's) that are currently held by Calpine Corporation and are banked in the Yolo-Solano Air Quality Management District (YSAQMD):

	(units: pounds per quarter)			
ERC Certificate No.	Q1	Q2	Q3	Q4
EC-209	0	6,888	0	3,542
EC-210	0	10,620	0	4,414

Roseville Electric will be requesting that the interdistrict transfer of these ERC's, for application to the Roseville Energy Park in Placer County, be placed on the District Board agenda for YSAQMD on June 9, 2004 and for PCAPCD on June 10, 2004.

II. New ERC's. The City of Roseville has entered into agreements with Energy 2001, Inc. which include an option to purchase at least 10 tons of new NOx ERC's that may be created at the existing Lincoln Landfill, located within Placer County. Energy 2001, Inc. is currently constructing a power generation facility at the landfill, replacing existing power generators. After the replacement generators are in service, additional control equipment could be installed to reduce NOx emissions and result in certification of new NOx ERC's. It is anticipated that the new NOx ERC's will be certified before the Roseville Energy Park enters commercial operation.

PLACER COUNTY AIR POLLUTION CONTROL DISTRICT

11464 B Avenue, Auburn, CA 95603 • (530) 889-7130 • Fax (530) 889-7107
Thomas J. Christofk, Air Pollution Control Officer
www.placer.ca.gov/apcd

May 6, 2004

Mr. Robert Hren, REP Project Manager
Roseville Electric
2090 Hilltop Circle
Roseville, CA95747

Subject: Emission Reduction Credits

Dear Mr. Hren:

The District has received your letter regarding the disclosure of confidential emission reductions for the Roseville Energy Park project. The two emission reduction credit (ERC) certificates, EC-209 and EC-210, issued by Yolo-Solano AQMD (YSAQMD), identified will no longer be treated as confidential and will be identified in the Preliminary Determination of Compliance (PDOC) after staff have reviewed YSAQMD's background documentation on these ERCs.

The attachment to your letter, Item II., New ERCs, discussed potential ERCs from the landfill gas power generators which are being constructed by Energy 2001. This source operated an engine for a very limited time and shut the engine down more than a year ago. Energy 2001 has been issued an Authority to Construct to install two engines. We have not received a notification of completion of construction and presume the engines have not been installed or operated.

District Rule 504, Emission Reduction Credits, identifies the process for quantifying and certifying emission reductions for use of offsets. As stated in the Rule 504, Section 301, only actual emission reductions shall be certified as ERCs. At this time, there are no documented actual emissions reductions at Energy 2001 which could be certified ERCs under Rule 504. The District does not consider emission reductions which might be certified at some future date a viable source of offsets for the Roseville Energy Park.

We do recognize that Roseville Electric is continuing efforts to secure additional ERCs for offsets. Those credits which have been obtained will be discussed in the PDOC. The PDOC will indicate that that there may be shortfall of offsets and the identification of additional ERC certificates for offsets are required before we can prepare a final Determination of Compliance. This must include the ERC certificate number, quantities for each quarter, location of the source of ERCs, and distance of source of ERCs from the Roseville Energy Park.

You might consider other options including reducing the design capacity and resulting emissions from the project or reducing the hours of operation and resulting emissions to the extent that offsets are available at this time.

As you are aware, any ERCs which are to be transferred from outside the District do need to be approved by both District Boards pursuant to the California Health and Safety Code Section 40709.6, Offset by Reductions Credited to Stationary Source Located in Another District. This approval must be obtained prior to the District's issuance of a final Determination of Compliance.

We have scheduled an agenda item this matter for the June 10, 2004 District Board meeting. All available ERCs which are to be transferred should be identified along with a justification for approval under Section 40709.6. This information is needed by no later than May 21, 2004 so that we may prepare the Board package. If not available at that time, the next Board meeting is scheduled for August. Please be aware that failure to obtain approval or delaying approval of interdistrict transfer of ERCs will delay or prevent the issuance of the final Determination of Compliance.

Please contact me at (530) 889-7133 if you have any questions.

Sincerely,

John Finnell
Sr. Air Pollution Control Engineer

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