AIR POLLUTION CONTROL DISTRICT
COUNTY OF SAN DIEGO

December 6, 2002

DOCKET
01-AFC-24
DATE DEC 0 6 2002
RECD. DEC 17 2002

Bob Eller
Project Manager
California Energy Commission
1516 Ninth Street
Sacramento CA 95814-5512

Final Determination of Compliance
Palomar Energy Project

Enclosed is the San Diego County Air Pollution Control District Final Determination of Compliance (FDOC) for the Palomar Energy Project (No. 01-AFC-24) proposed by Palomar Energy, LLC. The FDOC includes the District's evaluation of the project's compliance with applicable District rules and regulations, and proposed terms and conditions necessary to ensure compliance of the project with District rules and regulations during start-up, commissioning and on-going operations.

The District has determined that the project as proposed will comply with all applicable District rules and regulations if it is constructed and operated in accordance with the information submitted in conjunction with the application for District Authority to Construct, the application for certification submitted to the CEC, and the terms and conditions of this FDOC.

Please be advised that the FDOC does not constitute a final PSD permit under 40 CFR 52.21 since the United States Environmental Protection Agency (USEPA) is in consultation with the U.S. Fish and Wildlife Service (USFWS) pursuant to Section 7 of the Endangered Species Act (ESA). The consultation concerns the potential impact of the Palomar Energy Project on federally protected species. No date has been projected for issuance of the biological opinion nor USEPA's review of that opinion. Once the evaluation and determinations regarding Endangered Species issues have been completed, and after the District has considered CEC's environmental justice analysis and public comments received by the CEC on environmental justice, the District will issue a supplement to this FDOC as the final PSD permit. The final PSD permit may contain revised terms and conditions necessary to ensure compliance with PSD requirements, including those of the ESA and environmental justice.

PROOF OF SERVICE (REVISED 9/22/02) FILED WITH
ORIGINAL MAILED FROM SACRAMENTO ON 12.17-02
K.AH.

The District appreciates the efforts of the CEC staff to assist the District in understanding the CEC approval process and facilitating gathering of information. If you have any questions concerning the above or the enclosed FDOC, please contact Evariste Haury at (858) 650-4609, Dan Speer at (858) 650-4607 or the undersigned at (858) 650-4590.

MICHAEL R. LAKE
Assistant Director

cc: Ray Kelly, Sempra Energy, LLC
Mike Tolstrup, ARB-SSD
David Wampler, EPA, Region IX

FINAL
DETERMINATION OF COMPLIANCE

PALOMAR ENERGY PROJECT

SAN DIEGO AIR POLLUTION CONTROL DISTRICT
Application Number 976846

December 06, 2002

Evariste Haury
Dan Speer
Mike Lake

Project Engineer:	**Evariste Haury**
Senior Engineer:	**Daniel Speer**

Application Number: **976846**

Site ID Number:	**8013A**
Fee Schedule:	**20F**
BEC:	**New**

I. APPLICATION INFORMATION

Owner / Operator: Palomar Energy, LLC

Mailing Address: 101 Ash St.,
San Diego, CA 92101

Equipment Address: Intersection of Vineyard Avenue and Enterprise St.,
Escondido, California.

Contact:	Ray Kelly, Sempra Energy Resources
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I. PROJECT DESCRIPTION

Palomar Energy, LLC (Palomar) proposes to construct the Palomar Energy Project. This project consists of a natural gas-fired, combined-cycle power plant with a nominal base load gross power output of 517 MW and with a corresponding heat input of 1,722 MMBtu/hr per turbine (at 62 °F). The Palomar Energy Project will utilize two General Electric Frame 7FA combustion turbine generators (CTGs) each with heat recovery steam generators (HRSGs) and auxiliary duct burners. Each of the combustion turbine generators will be rated at 165 MW (at 62 °F). Both Turbines will feed a single shared steam turbine generator rated at approximately 187 MW (base load).

The Palomar Energy Project is subject to the approval of the California Energy Commission (CEC) because the proposed power plant has a nominal rating greater than 50 MW. Palomar filed an application for certification (AFC) with the CEC on November 28, 2001. The San Diego Air Pollution Control District (District) is considered a responsible agency for this approval and is required to submit a Preliminary Determination of Compliance (PDOC) and a Final Determination of Compliance (FDOC) to the CEC. Pursuant to District Rule 20.5 the FDOC review is functionally equivalent to an Authority to Construct review.

The District submitted the PDOC on July 3, 2002 and initiated a public comment period. Comments were received from the CEC, California Air Resources Board (ARB), and the Applicant during the 30-day public comment period. Comments were also received from the U.S Environmental Protection Agency (EPA) after the close of the public comment period. This FDOC is issued based on consideration of all comments received.

The Palomar Energy Project site is located in the city of Escondido, west of Interstate 15 and south of State Highway 78, approximately 600 feet southwest of the intersection of Vineyard Avenue and Enterprise Street. The project site is bounded on the north by a 49 MW gas fired combustion turbine plant operated by CalPeak Enterprise, on the east by existing industrial land uses, on the south by future industrial land uses, and on the west by an existing SDG&E transmission corridor and future industrial land uses. The project site is also located near a PG&E 44 MW power plant located at 2037 Mission Road.

The project will be fueled by natural gas, which will be supplied by the San Diego Gas and Electric Company. No provisions for use of an alternative fuel in the event of a curtailment of the natural gas supply are proposed by the applicant.

II. EQUIPMENT DESCRIPTION

Palomar has proposed to construct and operate the following equipment at this facility under application No. 976846:

- Power Station Unit #1 consisting of: one nominal 165 MW natural-gas fired combined-cycle General Electric Power Systems Frame 7FA gas turbine generator, S/N to be determined, with dry low-NOx combustors, a heat recovery steam generator, a 195 MMBtu/hr (HHV) auxiliary duct burner, a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator shared with Power Station Unit # 2.

- Power Station Unit #2 consisting of: one nominal 165 MW natural-gas fired combined-cycle General Electric Power Systems Frame 7FA gas turbine generator, S/N to be determined, with dry low-NOx combustors, a heat recovery steam generator, a 195 MMBtu/hr (HHV) auxiliary duct burner, a selective catalytic reduction unit, an oxidation catalyst, and a steam turbine generator shared with Power Station Unit #1.

- A shared 130,000 gallons per minute (GPM) wet cooling tower with 7 cells and high efficiency drift eliminators.

III. PROCESS DESCRIPTION

The Palomar Energy Project is a combined-cycle power plant including two combustion turbine generators (CTGs). Each CTG will be equipped with a heat recovery steam generator (HRSG) and will drive an electrical generator which will produce nominally 165 MW of electricity. The exhaust from the CTGs will be used to produce steam to power a steam turbine, which drives an additional 187 MW (base load) electrical generator thus increasing the power produced. Each HRSG will also be supplied with a duct burner which will be capable of increasing the steam turbine output to total the rated capacity.

The CTGs will be equipped with dry-low–NOx (DLN) combustors designed to operate on natural gas only. Each HRSG will be equipped downstream of all combustion processes with a selective catalytic reduction (SCR) system using aqueous ammonia to control oxides of nitrogen emissions to 2.0 parts per million by volume (ppmv) as NO_2 at 15% O_2 on a 1-hour average basis except for times when the duct burners are fired or during transient operations. During such periods NO_2 will be controlled at the same level but on a 3-hour average basis. Each HRSG will also be equipped with an oxidation catalyst to control CO and VOC emissions. CO emissions will be controlled to 4 parts per million by volume (ppmv) corrected to 15% O_2, averaged on a 3-hour basis, VOC emissions will be controlled to 2 ppmv (as methane) corrected to 15% O_2 and also averaged on a 3-hour basis.

Each HRSG produces steam by transferring heat from the CTG exhaust to condensate and feed water. Each of the two HRSGs is a multi-pressure, natural circulation boiler equipped with a duct connecting the CTG exhaust, duct burners, outlet duct and exhaust stack. Each of the two exhaust stacks is 17 feet in diameter and 110 feet high. At times such as peak electrical demand periods, duct burners in each HRSG will be used to heat the CTG exhaust gas to increase the HRSG's steam turbine work output.

A seven-cell wet cooling tower utilizing reclaimed water from the City of Escondido Hale Avenue Resource Recovery Facility is proposed to provide heat rejection for the steam cycle. The cooling tower will have a design water flow rate of up to 130,000 gallons per minute. The cooling tower is equipped with drift eliminators and includes plume abatement techniques to minimize the formation of a visible moisture plume.

Each combustion turbine exhaust will be equipped with a Continuous Emission Monitoring System (CEMS) for NOx, CO, and O_2. The CEMS will generate a log of emissions data for compliance documentation.

Because the Palomar Energy Project will operate as a merchant plant, market demand will likely dictate the power to be produced. As a result, the load on the equipment will vary. The emissions from the gas turbines will therefore be affected by several factors, including mode of operation, use of duct burners and ambient meteorological conditions. Each HRSG will be equipped with a duct burner. These duct burners will enable the heat recovery steam generators to produce additional steam for up to a total of 4,000 hours per year of operation combined for both turbines at the rated duct burner fuel consumption. The basic operational modes primarily affecting emissions are startups, shutdowns, short transients and normal operations (including peak load). The applicant has provided performance data based on vendor guarantees for the estimated emission rate for each criteria pollutant when operating under different loads, different ambient temperatures, and with and without duct burners in operation. The expected worst-case controlled emissions used in various aspects of the evaluation are presented in Tables 1a, 1b, and 1c.

Startup is defined as the period beginning with ignition in a gas turbine and lasting until the gas turbine has reached a continuous and stable operating level (typically at greater than 60% of base load capacity) and the emissions control systems have reached minimum required operating conditions. An extended startup occurs when the steam cycle has not been in operation during the preceding 48 hours. A regular startup occurs when the steam cycle has been in operation within the last 48 hours. Shutdown is a period beginning with the lowering of the output of a gas turbine below 50% of its load capacity and ending when combustion has ceased. Emissions during startups and shutdown are significantly higher than during steady state operation. The applicant estimates that there will be 50 extended starts per turbine per year, 182 regular starts per turbine per year and 232 shutdowns per turbine per year.

IV. EMISSION CALCULATIONS

Combustion Equipment Emissions

Project emissions of NOx, CO, SOx, VOC, and PM_{10} were estimated based on data supplied by the manufacturer for four load conditions and three ambient temperatures. The loads examined were: maximum load (100%) with duct firing, maximum load (100%) without duct firing, mid-load (75% without duct firing) and low load (50% without duct firing). The temperatures examined were maximum summer temperature (110°F), typical average temperature (62°F) and minimum winter temperature (20°F). SOx emissions are based on the sulfur content of the natural gas (0.75 grain sulfur per 100 scf of gas) and a typical higher heating value (HHV) of 1,020 Btu/scf.

Maximum Hourly Emissions

The mass emission rates specified in Tables 1a, 1b and 1c are extracted from the general emission data provided by the applicant and described in the preceding paragraph. These emissions reflect the maximum emissions when the equipment operates at certain operating conditions and certain temperatures. These emissions rates were used in calculating daily and yearly emissions. The following operating conditions were selected because operating at these loads and conditions will result in maximum emissions from the turbines and the duct burners.

Table 1a provides emissions when the turbines are operating at maximum load without duct burners at 62°F (average temperature in San Diego). This operation is referred to as base load operation.

Table 1a

Maximum Controlled Emissions per Turbine

Operation at 100% load and 62°F

Without duct burner firing

Pollutant	Concentration, ppmvd @ 15% O_2	Emission Rate, lbs/hr
NOx	2.0 (3-hr avg)	12.5
CO	4.0 (3- hr avg)	15.3
VOC	2.0 (3-hr avg)*	3.8
PM_{10}		11.1
SOx		3.8
* Based on source test and surrogate relationship with CO		

Table 1b provides emission data when the turbines are operating at 100% load at 62°F with the duct burners in operation. This operation is referred to as peak load operation and will result in maximum emissions during average temperatures.

Table 1b

Maximum Controlled Emissions per Turbine

Operation at 100% load and 62°F

With duct burner firing

Pollutant	Concentration, ppmvd @ 15% O_2	Emission Rate, lbs/hr
NOx	2.0 (3-hr avg)	13.9
CO	4.0 (3-hr avg)	16.9
VOC	2.0 (3-hr avg)*	6.8
PM_{10}		13.8
SOx		4.2
* Based on source test and surrogate relationship with CO		

Table 1c presents emissions of the turbines at 100% load during winter (20°F) with the duct burner operating. This scenario will result in maximum hourly emissions during peak load operations.

Table 1c

Maximum Controlled Emission per Turbine

Operating at 100% load and 20°F

With duct burner firing

Pollutant	Concentration, ppmvd @ 15% O_2	Emissions Rate, lbs/hr
NOx	2.0 (3-hr avg)	14.9
CO	4.0 (3- hr avg)	18.1
VOC	2.0 (3-hr avg)*	7.3
PM_{10}		14.0
SOx		4.5
* Based on source test and surrogate relationship with CO		

Startup and Shutdown Emissions

Startup/shutdown emissions are based on vendor data and expected startup profiles of the turbines, and assumed partial control from selective catalytic reduction for NOx and from oxidation catalyst for CO and VOC. During a startup or shutdown event the overall emission control effectiveness will depend on operating temperature and several other variables.

Applicant provided both typical average and estimated maximum emissions during startup and shutdown events. The typical average emissions are a combined total for both turbines, are given in pounds per event, and were used to estimate the annual potential to emit. These emissions are given in Table 1d.

Table 1d

Anticipated Typical Emissions for Both Turbines

During Startup and Shutdown Conditions

Condition	Emissions, lbs/event					Duration
	NOx	CO	PM_{10}	VOC	SOx	
Regular start	140	920	44.4	74	10	2 hours
Extended start	200	3600*	88.8	100	20	4 hours
Shutdown	25	160	5.6	12	1.3	0.5 hours

* This level of emissions is limited by condition to 3384 lbs/event which is representative of modeling

The estimated maximum emissions per turbine, in pounds per hour, were used for modeling to show that ambient air quality standards will not be exceeded due to the project. These emission rates are given in Table 1e.

Table 1e

Anticipated Typical Emissions Per Turbine

During Startup or Shutdown Conditions

	Emissions, lbs/hour				Duration
	NOx	CO	PM_{10}	SOx	
Startup/Shutdown	100	1,692	14.1	10	4 hours

Criteria Pollutants

<u>Maximum Daily and Annual Emissions</u>

The following assumptions were made to estimate maximum daily and annual emissions for each turbine:

- 8,760 hrs/yr total operating time (including base load, peak load and startup/shutdown operation)
- 390,000 MMBtu/yr of total duct burner heat input (equivalent to 2,000 hrs/yr at peak output with duct burner operation)
- 50 extended startups per year (up to 4 hours in duration)
- 6,080 hrs/yr at base load (100 percent load without duct firing)
- 182 regular startups per year (up to 2 hours in duration
- 232 shutdowns per year (up to 0.5 hours in duration)
- Both units could undergo startup and /or shutdown on any given day
- The SCR and oxidation catalyst will provide partial reduction of emissions during startup and shutdown.

Worst case daily emissions for a single turbine

Worst-case daily emissions for NOx, CO, and VOC occur when there is one extended start that day and the turbine operates at 100% load with the duct burner operating the remainder of the day. Worst-case daily emissions for PM_{10} and SO_2 will occur when the turbine is operated at 100% load with the duct burner operating. The maximum daily emissions were estimated as follows:

NOx = (100 lbs/4 hrs)(4 hrs/day) + (14.9 lbs/hr)(20 hrs/day)
= 398 lbs/day

CO =(1692 lbs/4 hrs)(4 hrs/day) + (18.1 lbs/hr)(20 hrs/day)
= 2,054 lbs/day

VOC = (50 lbs/4 hrs)(4 hrs/day) + (7.3 lbs/hr)(20 hrs/day)
= 196 lbs/day

SOx = (4.5 lbs/hr)(24 hrs/day)
= 108 lbs/day

PM_{10} = (14 lbs/hr)(24 hrs/day)
= 336 lbs/day

Annual emissions for a single turbine

Annual emissions per turbine were estimated based on 50 extended startups, 182 regular startups and 232 shutdowns and the turbine operation at 100% load for the remainder of the year, including 2,000 hours at peak load with the duct burners operating:

NOx = [(12.5 lbs/hr)(6,080 hrs/yr) + (13.9 lbs/hr)(2,000 hrs/yr)+(100 lbs/event)(50 events/yr) + (70 lbs/event)(182 events/year)+(12.5 lbs/event)(232 events)] ÷ (2,000 lbs/ton)
=62.2 tons/year

CO = [(15.3 lbs/hr)(6,080 hrs/yr) + (16.9 lbs/hr)(2,000 hrs/yr)+(1,692 lbs/event)(50 events/yr) + (460 lbs/event)(182 events/year)+(80 lbs/event)(232 events/year)] ÷ (2,000 lbs/ton)
= 156.9 tons/year

VOC = [(3.8 lbs/hr)(6,080 hrs/yr) + (6.8 lbs/hr)(2,000 hrs/yr)+(50 lbs/event)(50 events/yr) + (37 lbs/event)(182 events/yr)+(6 lbs/events)(232 events/yr)] ÷ (2,000 lbs/ton)
= 23.7 tons/yr

SOx = [(3.8 lbs/hr)(6,080 hrs/yr) + (4.2 lbs/hr)(2,000 hrs/yr)+(10 lbs/events)(50 events/yr)+(5.0 lbs/event)(182 events/yr)+(.65 lbs/event)(232 events/yr)] ÷ (2,000 lbs/ton)
= 16.5 tons /yr

PM_{10} =[(11.1 lbs/hr)(6,080 hrs/yr) + (13.8 lbs/hr)(2,000 hrs/yr)+(44.4 lbs/event)(50 events/yr) + (22.2 lbs/event)(182 events/yr) + (2.8 lbs/hr)(232 events/yr)] ÷ (2,000 lbs/ton) = 51.0 tons/yr

Worst case Emissions (both turbines)

Worst-case daily emissions are calculated assuming the worst-case hourly emissions scenario for any of the four point loads and three ambient temperatures listed above. For NOx, CO, VOC the turbines are assumed to operate 20 hours at maximum load plus 4 hours in startup condition each. PM_{10} and SOx are based on 24 hours of maximum operation.

NOx = 2[(14.9 lbs/hr)(20 hrs/day)] +(200 lbs/4 hrs)(4 hrs/day)
= 796 lbs/day

CO = 2[(18.1 lbs/hr)(20 hrs/day)] +(3384 lbs/ 4 hrs)(4 hrs/day)
= 4,108 lbs/day

VOC = 2[(7.3 lbs/hr)(20 hrs/day)] +(100 lbs/ 4 hrs)(4 hrs/day)
= 392 lbs/day

SOx = 2[(4.5 lbs/hr)(24 hrs/day)] = 216 lbs/day

PM_{10} = 2[(14 lbs/hr)(24 hrs/day)] = 672 lbs/day

Annual worst-case emissions are the same for both turbines. The totals for both are:

NOx	= 2(62.2 tons/year)	= 124.4 tons/year
CO	= 2(156.9 tons/yr)	= 313.8 tons/year
VOC	= 2(23.7 tons/yr)	= 47.4 to/year
SOx	= 2(16.5 tons/yr)	= 33.0 tons/year
PM_{10}	= 2(51.0 tons/yr)	= 102.0 tons/ year

Cooling Tower Emissions

The cooling tower is a source of PM_{10} emissions. One cooling tower, consisting of 7 cells, will be used for process cooling at the Palomar Energy Project. The tower will circulate 130,000 gallons per minute of water. The maximum blowdown quantity will be 4,000 ppm total dissolved solids (TDS). High efficiency drift eliminators with a drift rate of 0.0005% (based on manufacturer's specifications) will be used to control the particulate emissions from the towers. The applicant assumes that 50 percent of the TDS are PM_{10}. The applicant provided documentation for this assumption, including a technical paper (Calculating Realistic PM_{10} Emissions from Cooling Towers, Reisman and Frisbie, 2001, Presented at the 94th Annual Air & Waste Management Association's Meeting). This publicly available document, provides the background for the assumption that 50 percent of the TDS is PM_{10}. The applicant has stated that this assumption was accepted in the permitting process of recent projects around the country including California. The District determined based on a modeling analysis that even if all (100%) of the TDS was assumed to be PM_{10}, no significant air quality impacts would result.

<u>PM_{10} Emissions</u> (assuming 50 percent of the TDS is PM_{10})

PM_{10} (lbs/hr) = (coolant circulation rate) x (drift rate) x (TDS concentration) x (density of coolant) (% of PM_{10})

= 130,000 gpm x 0.0005/100 x 4,000 lbs solids/ 10^6 lb of water x 60 min/hr x 8.34 lbs/gal x 50%

= 0.65 lbs/hr

PM_{10} (lbs/day) = 0.65 lbs/hr x 24 hrs/day

= 15.61 lbs/day

PM_{10} (tons/year) = 0.65 lbs/hr x 8,760 hrs/yr / 2,000 lbs/ton

= 2.8 tons/yr

Table 2a presents a summary of the estimated maximum gas turbine emissions

Table 2a

Maximum Emissions from Each Turbine During Normal Operations including startups

Pollutant	Lbs/hour	Lbs/day	Tons/yr
NOx	100	398	62.2
CO	1,692	2054	156.9
VOC	18.5	196	23.7
PM_{10}	14.0	336	51.0
SOx	4.5	108	16.5

Table 2b includes the emissions from the cooling tower assuming 50% of the TDS is PM_{10}.

Table 2b

Maximum Facility Emissions

(Assuming 50% of the TDS is PM_{10})

Pollutant	Lbs/hour	Lbs/day	Tons/yr
NOx	200	796	124.4
CO	3,384	4,108	313.7
VOC	37	392	47.3
PM_{10}	28.7	688	104.8
SOx	9	972	33.1

Commissioning Period:

After the equipment is first installed, the equipment is "run-in" and cleaned using steam blow/boilout of the equipment. Steam blow/boilout refers to purging of foreign material from the inside of the steam paths and from the outside of the tubes using steam when the turbines and HRSG first come on line. The steam cleans out the equipment, including mill scale, protective coatings, and debris introduced during construction. The steam for this activity is generated by the HRSG, and the turbine must be run at a low load for the equipment to function properly. Even though it involves firing fuel in the combustion turbine, steam blow/boilout does not constitute operation of a combustion turbine, but rather is still considered a construction activity.

Following construction of the power plant and prior to full commercial operation, the combustion turbine generators, the steam turbine generator, emission control equipment, heat recovery steam generator and other equipment will be tested and tuned. This will require operation of the CTGs at loads varying from 0% to 100% of full load. During this period, because the CTG burners may not yet be tuned for optimal emissions and because the post combustion control equipment will not yet be in full operation, emissions from the plant will be higher than normal operating emissions. The plant is expected to operate less than 300 hours per turbine during this commissioning period. The emissions during this commissioning period were estimated by the applicant based on manufacturers' data and past applications submitted by others for similar facilities. The estimated commissioning emissions are summarized below in Table 3.

Table 3

Potential Emissions During Commissioning Period

Pollutants	Single CTG (lbs/hr)	Both CTGs (tons/com.period)
NOx	450	124.4 (annual cap)
VOC	14.7	4.4
CO	2,000	600
PM	14.0	4.2 (CTG only)
SOx	4.5	1.4

Toxic Emissions

Based on average annual temperature (62 °F) conditions, the following assumptions were made to estimate maximum toxic air contaminant emissions:

- Average Base Load Heat Input: 1,722 MMBtu/hr per turbine
- Average Peak Load Duct Burner Heat input: 180 MMBtu/hr per duct burner (HHV)
- Natural gas heating value 1,020 Btu/scf
- Natural gas density 16 lb (CH_4) / 385 scf = 0.0416 lb fuel / cf NG
- Exhaust F- Factor 764.18 dscf exhaust /lb fuel @ 15%O_2 EPA Method 19
- Control Efficiency: 50% VOC reduction (including toxics)

Average Base Load Fuel Usage (turbine) = (1,722 MMBtu/hr)(scf/1,020 Btu)

= 1.69 MMscf fuel/hr for each turbine

= 3.38 MMscf fuel/hr for both turbines

Average Peak Load Fuel Usage (duct burner) = (180 MMBtu/hr)(scf/1,020 Btu)

= 0.18 MMscf fuel/hr for each duct burner

= 0.35 MMscf fuel/hr for both duct burner

Total Fuel Usage (per turbine and duct burner) = 1.87MMscf fuel/hr

Exhaust Flow = (764.18 dscf exhaust/lb fuel)(0.0416 lb fuel/scf fuel)(1.85 MMscf fuel/hr)

= 59.45 MMdscf fuel/hr @ 15% O_2

Emission calculations for the turbines were based on California Air Toxics Emissions Factors (CATEF), which are generally consistent or conservative compared with District emissions factors for gas turbines. In the case of formaldehyde and acrolein, the CATEF emission factors are higher than the corresponding District emission factors. There is also information in the EPA database (on which the District default emission factor for formaldehyde is based) suggesting that formaldehyde emissions for the type of turbine being proposed may be substantially less than either of the CATEF or District factors. Consequently, the CATEF emission factors used in the Health Risk Assessment are conservative and are acceptable to the District.

Ammonia emissions were calculated as follows based on the proposed 10 ppm ammonia slip emission limit:

$$NH_3 = (10/10^6)(59.45 \text{ MMscf/hr})(17 \text{ lbs } NH_3/385 \text{ scf}) = 26.25 \text{ lbs/ hr}$$

The applicant estimated 27.5 lbs/hr ammonia emission rate for use in their toxic analysis.

Even though ARB Guidance recommends an ammonia limit of 5.0 ppm at 15% oxygen, all air toxic requirements were satisfied at an emission rate of 10.0 ppmv at 15% oxygen. Therefore, an ammonia limit of 10 ppmv will be allowed.

For polyaromatic hydrocarbon emissions (PAHs), the CATEF factors are speciated for specific toxic air contaminant PAHs, whereas the District default is not. For this HRA, the emission factors for all non-regulatory PAHs were summed. Most of the PAHs for this project are non-regulatory PAHs, and are comparable to emissions estimated from the District default emission factor, corrected for naphthalene. The HRA nevertheless conservatively assumed all non-regulatory PAHs to have the same unit risk as benzo(a)pyrene. The same conservative approach has been used for other recent applications of this type and is acceptable to the District.

Toxic air contaminant emission calculations for the cooling towers were based on City of Escondido data on maximum concentrations of toxic metals and maximum total dissolved solids levels from sampling of the reclaimed water proposed to be used in the cooling tower, maximum cooling recirculation rates, and a drift fraction of 0.0005%. The applicant submitted a Health Risk Assessment with its application which included information concerning possible toxic air contaminants from the cooling tower as well as the turbine/HRSG stacks. However, information was subsequently received by the District suggesting the presence of other toxic air contaminants. Therefore, the District requested that the applicant provide additional information about other possible toxics contaminants present in the cooling water for evaluation. The applicant subsequently provided a supplemental HRA which considers additional toxic compounds that may be present in the cooling water. The District has reviewed the Supplemental Health Risk Assessment (HRA), dated November 2002 and prepared by ENSR for the Palomar Energy, LLC natural gas-fired power plant cooling towers. This supplemental health risk assessment was conducted in response to the District efforts to ensure that all toxic air contaminants (TACs) that could reasonably be expected to be emitted from the cooling tower water were evaluated. The original assessment included only metals in the treated water from the Hale Avenue facility in Escondido. A number of additional volatile and non-volatile TACs were identified for which there was HARRF effluent data or for which emissions would be expected and which also had emission factors. These additional chemicals were included in the supplemental risk assessment. In addition, a number of TACs of concern were excluded from consideration, and justification for this was provided. The District has evaluated these justifications and considers them to be appropriate.

The District's conclusion is that the supplemental health risk assessment for the cooling towers is consistent with State and District Guidelines and that the estimated health risks from the cooling towers, when added to those for the turbines, are less than the District risk management criteria of 1 per million cancer risk and acute and chronic health hazard indices less than 1 at all likely offsite receptors. Specific comments are as follows.

1. Emission calculations for the cooling towers were based on City of Escondido quarterly effluent water quality analysis from the Hale Ave. facility for 1995-2002. Emission rates were calculated using this data and water re-circulation or makeup rates. Emissions for TACs without effluent data were calculated using SDAPCD emissions factors. The emissions appear to be correctly calculated. Emission calculations also include emission reduction resulting from tertiary treatment where appropriate.

2. The HRA concludes that the maximum lifetime cancer risk for the cooling towers is 0.0109 in a million at a location in the elevated terrain of the Coronado Hills approximately 3 kilometers west of the proposed plant. This was based on refined air dispersion modeling using ISC3 for lower elevations and AERMOD for elevated terrain. Since the peak occurs in elevated terrain, the AERMOD results are of primary concern. AERMOD calculations were done using meteorology data based on District measurements of wind speed and direction for the Escondido area together with upper air data from Miramar Air Station. The Modeling and Meteorology Section has determined that the AERMOD modeling used in this HRA provides acceptable estimates of air dispersion for this project.

3. Using the results of the dispersion modeling and the same emissions data, the District independently calculated the maximum cancer risk from the cooling towers to be 0.0104, which is considered to be good agreement. Since the District has previously verified the risk for the turbines to be no more than 0.94 in a million, the total cancer risk from the project should be no more than 0.95 in a million.

4. The District also verified the calculations of non-cancer chronic and acute health hazard index for the cooling tower. The maximum chronic health hazard index (HHI) for the cooling towers estimated by the District to be 0.0022. Since the total project chronic HHI was originally calculated to be 0.21, the contribution from the cooling towers is negligible. The maximum acute health hazard index (HHI) for the cooling towers was estimated by the District to be 0.00019. Since the total project acute HHI was originally calculated to be 0.31, the contribution from the cooling towers is negligible, and both are less than the regulatory level of concern.

5. Review of the health risk assessment showed that the latest OEHHA-approved health values were used with the exception that chronic RELs for ammonia, sodium hydroxide, methyl ethyl ketone, fluoride, lindane, antimony, and copper have been withdrawn by OEHHA as of July 2002 and are no longer appropriate to use in HRAs. This means that the chronic HHI for the cooling towers is less than was calculated in

the HRA. Since the chronic impact from the project is well below the level of concern, this has negligible impact.

6. The health risk assessment also included a re-analysis of the risk from the turbines. The District had previously approved the risk assessment for the turbines. The District has not yet reviewed the revised turbine HRA. The results of the turbine HRA will be revised if necessary based on that review.

V. RULES ANALYSIS

New Source Review (Major Stationary Sources and PSD Sources)

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

This subsection of the rule requires that Best Available Control Technology (BACT) be installed on a pollutant-specific basis if emissions exceed 10 lbs/day for each specified criteria pollutant (except for CO for which the BACT threshold is 100 tons/yr). This subsection also requires that Lowest Achievable Emission Rate (LAER) be installed on a pollutant-specific basis if emissions exceed 50 tons/yr for NOx or VOC. Because the District is in attainment status for the National Ambient Air Quality Standards (NAAQS) for CO, SOx and PM_{10}, LAER does not apply to these pollutants. BACT however applies for NOx, VOC, SOx, and PM_{10} because the District is non-attainment for the state ambient air quality standards for ozone (for which NOx and VOC emissions are precursors) and PM_{10} as required by (Rule 20.3(d)(1)(i)). Additionally BACT applies for CO and PM_{10} if they trigger PSD major source thresholds of 100 tons/yr [Rule 20.3(d)(1)(vi)]. Based on emission estimates, LAER is triggered for NOx and BACT is triggered for CO, VOC, SOx, and PM_{10}.

Oxides of Nitrogen (NOx)

According to the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT/LAER for NOx emissions from this equipment is either a NOx emission concentration of 2.5 ppm based on a 1-hour averaging period or 2.0 ppm based on a 3-hour averaging period, both calculated at 15% oxygen. However ARB is revising its BACT/LAER guidance for power plants to include limits achieved or proposed by more recent projects. The District consulted other BACT / LAER Clearinghouses including those of the other air districts, EPA and ARB. The Duke Energy Morro Bay power plant in San Luis Obispo County, and the ANP Blackstone Power Plant in Massachusetts were the only plants permitted at 2.0 ppm based on a one-hour averaging period. The Duke Energy Power plant has not been built yet. The ANP Blackstone power plant has been in operation since May 2001. Operating data from the Blackstone plant indicates some periods of operation where NOx emissions are above 2.0 ppm for both 2-hour and 3-hour periods. Its permit provides for higher NOx emission limits when operating with power augmentation specifically, 3.5 ppm @ 15% O_2 when steam power augmentation is used. The facility must also meet a 12-month rolling average of 2.3 ppmv NOx @ 15% O_2. The 2.0 ppm one-hour average limit at the Blackstone plant is only applicable when the turbines are operated without power augmentation, and excludes startups and shutdowns.

For the Palomar project, a 2.0 ppm, 3-hour Average NOx limit should be achievable with and without duct burner operation. The District reviewed the two calendar quarters (2002) of ANP Blackstone CEMS data. If periods when duct firing, transient operations, startups or shutdowns are occurring are excluded, the ANP Blackstone meets the 2.0 ppm one-hour average limit. Even though the review is based on two calendar quarters data, the District believes that the information provided is sufficient to confirm that the 2.0 ppm one-hour average limit has been demonstrated during certain operating conditions. No other demonstrated lower BACT/LAER limits were found by searching RACT/BACT/LAER Clearinghouses. Therefore, the 2.0 ppmv, with a 3-hour average is recommended as LAER for operation with duct burners and during any clock hour when the difference between the maximum MW produced by the generator train and the minimum MW produced by the generator train exceeds

+ 25 MW (transient periods), and 2.0 ppmv based on a 1-hour average for all other operations.

To meet LAER, the applicant also evaluated the XONON combustion system, the SCONOx system, a dry-low-NOx (DLN) plus selective catalytic reduction (SCR) system, and a combination of water/steam injection and SCR system. The XONON system, although technically feasible for large-scale turbines, is not an available technology for the GE Frame 7FA. This technology cannot consistently meet the lower emission rates achievable by DLN plus SCR. The SCONOx system would have a larger energy impact than an SCR system and has not yet been achieved in practice on large gas turbines. The water / steam injection plus SCR has been demonstrated in practice, but this technology will use more catalyst and more ammonia and will increase ammonia emissions. Also, this technology cannot consistently meet the lower emission rate achievable by DLN plus SCR. The combination of DLN with SCR technology is commercially available and installed on numerous large turbines. This technology has achieved 2.0 to 2.5 ppm at 15% oxygen on several projects. The applicant has proposed this technology to meet the BACT/LAER requirement. A continuous emission monitoring system (CEMS) and annual source testing will be used to confirm compliance with the emission limit.

Carbon Monoxide (CO)

According to ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for CO emissions from this equipment is 6.0 ppm based on a 3-hr averaging period, calculated at 15 % oxygen. The applicant proposes to meet a limit of 4.0 ppm based on a 3-hr average, calculated at 15% oxygen. Because the ARB Guidance is being updated, other air districts, EPA and ARB Clearinghouses, have been consulted for more recent determinations. The Morro Bay power plant has a permit limit of 2.0 ppm with a tuning-in clause of 4.0 ppm for 12 months. Because the equipment has not yet been constructed this limit is not yet achieved in practice. The ANP Blackstone power plant in Massachusetts is equipped with an oxidation catalyst to control CO emissions. Even though the plant has been able to meet very low CO emission levels (close to 0 ppm) consistently during compliance testing, its CO permit limits are as follow: 3.0 ppm at 100% load, 4.0 ppm at 75% load and 20 ppm at 50 % load. The applicant has proposed to meet 4.0 ppm at a 3-hour average at all times. This will be more stringent than the ANP Blackstone permit conditions. The proposal will be in line with the most recent determination of other California air districts and lower than the ARB September 1999 BACT Guidance. Therefore the District has determined the limit of 4.0 ppm calculated at 15% oxygen on a 3-hour basis to be BACT for CO.

To meet this requirement, the applicant evaluated the use of an oxidation catalyst, which is the only post-combustion technology currently available to control CO, VOC, and toxic emissions. This technology is acceptable as BACT for CO. The applicant will therefore use an oxidation catalyst to meet the BACT level of 4.0 ppm at 15 % oxygen on a 3-hour average. A CEMS and annual source testing will be used to confirm compliance with this limit.

Volatile Organic Compounds (VOC's)

From the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, and from searching BACT Clearinghouses, BACT for gas turbines is 2.0 ppm VOC, measured as methane @ 15% O_2, based on a 1-hr averaging period. No lower limits were found by searching RACT/BACT/LAER Clearinghouses. Therefore, the ARB Guidance level of 2.0 ppm is recommended as BACT/LAER for gas turbines. In accordance with accepted test methods for VOC which require 3-1 hour samplings of exhaust, the averaging time for this limit must be based on 3-hours.

The applicant analyzed the use of an oxidation catalyst, which is the only post combustion technology currently available to control CO, VOC, and toxic emissions. An initial source test will be used to confirm compliance with these limits. Additionally, the source test data will be used to establish a correlation between CO emissions and VOC emissions to provide an accurate indicator of continued compliance with these limits using the CEMS data for CO.

Although the ARB Guidance identifies a 1-hour averaging time for VOC, compliance will be determined based on source test data and a surrogate relationship with CO because CEM technology is not available for VOC's. In addition to conflicting with standard VOC test methods, it would be impractical to have different averaging times for CO and VOC. Therefore, the emission limit for VOC will be based on a 3-hour averaging time.

Particulate Matter (PM_{10}) and Oxides of Sulfur (SOx)

From the ARB Guidance for Power Plant Siting and Best Available Control Technology, September 1999, BACT for this equipment is the use of natural gas that contains less than 1 grain of sulfur compounds per 100 standard cubic feet of natural gas. Public Utility Commission (PUC) quality natural gas sold in San Diego County is required to meet a maximum sulfur content limit of 0.75 grains of sulfur compounds per 100 standard cubic feet of natural gas. Therefore, use of PUC quality natural gas meeting this 0.75 grains limit is recommended as BACT. The applicant will be required to maintain documents showing the sulfur content of natural gas used. Any alternative supplies of natural gas must be approved by the District and meet this sulfur content limit.

Rule 20.3(d)(2) – Air Quality Impact Analysis (AQIA):

An Air Quality Impact Analysis (AQIA) is required for this project because the Project's Potential to Emit is greater than the District AQIA trigger levels and PSD significant emission rates for NOx, CO, and PM_{10}. The purpose of this analysis is to determine whether the proposed source will cause or contribute to an exceedence of the National Ambient Air Quality Standards, State Ambient Air Quality Standard, or PSD increments.

Dispersion modeling was conducted to analyze ambient impacts of project emissions of NO_x, CO, and PM_{10}. The applicant and their consultant (ENSR International) worked closely with the District in developing modeling and analysis procedures in support of demonstrating compliance with all applicable NSR and PSD requirements.

The impact analysis was performed with respect to the ambient air quality in the project vicinity, the air quality in the nearest Class I areas and the Air Quality Related Values (AQRVs) including visibility and acid deposition in the Class I areas.

In addition, during the commissioning and startup periods, hourly emissions of CO and NOx are expected to be much higher. Maximum CO and NOx emissions were modeled to determine whether emissions during these time periods would cause exceedances of the State or National Ambient Air Quality Standards for CO or NO_2. (See APCD Air Quality Impact and Prevention of Significant Deterioration Final Review Report, Appendix A).

In accordance with EPA and San Diego Air Pollution Control District New Source Review Guidance and modeling methodologies, maximum predicted concentrations and PSD increments associated with facility operations were determined for each pollutant and the applicable averaging period during Normal, Startup and Commissioning conditions. The maximum predicted concentrations were added to a worst-case background concentration for comparison to the National and State Ambient Air Quality Standards. Worst case background concentrations were determined from reviewing three years of monitoring data (1998-2000) taken from the District's Escondido air monitoring station, which was deemed to be the most representative of air quality in the facility area.

Significant Impact Levels (SILs) and PSD Class II increments during normal facility operation were also analyzed. The results indicate impacts are below the Significant Impact Levels for applicable pollutants. Therefore, no further Class II increment analysis was required.

The analysis also demonstrated that facility operations would not cause or contribute to an exceedance of the PM_{10} National Ambient Air Quality Standard or additional exceedances of the California Annual Ambient Air Quality Standard.

The modeling analysis for commissioning period conditions evaluated the maximum short-term NO_x and CO emissions. PM_{10} and SO_2 commissioning period emissions were not modeled because they are not significantly different than during normal operations. The results demonstrate that facility commissioning period operations will not cause or contribute to an exceedance of any National or California Ambient Air Quality Standards for NO_2 or CO. The results indicate that the 1-hour and 8-hour Class II area Significant Impact Levels for carbon monoxide (CO) may be triggered during the commissioning period. However, federal PSD increments have not been enacted for CO and the air quality impact analysis demonstrate that project CO emissions will not cause nor contribute to exceedances of either the California or National standards for CO.

The modeling analysis for startup conditions evaluated the maximum short-term NO_x and CO emissions. PM_{10} and SO_x startup emissions were not modeled because they are not significantly different than during normal operations. The results demonstrate that facility Startup operations will not cause or contribute to an exceedance of any National or California Ambient Air Quality Standards for NO_2 or CO. The results indicate that the 1-Hour and 8-Hour Class II area Significant Impact Levels for CO may be triggered during startups. However, federal PSD increments have not been enacted for CO and the air quality impact analysis demonstrates that project CO emissions will not cause exceedances of either California or National standards for CO.

For the AQIA, cooling tower PM_{10} emissions were included in the modeling to estimate maximum PM_{10} impacts for the entire facility. Twelve different modeling scenarios were employed with varying ranges of loads, duct firing on or off, and varying ambient temperature. PM_{10} emissions ranged from 11 to 14 lb/hr for each turbine depending on the modeling scenario, or a total of 22 to 28 lb/hr for the turbines. The cooling tower emissions were estimated to be 0.65 lb/hr using a 50% fraction of the total dissolved solids (TDS). This is, at maximum, less than 3% of the total PM_{10} emissions for the facility. Both AERMOD and ISC were used to determine the maximum estimated 24 HR PM_{10} impact anywhere in the vicinity of the facility, which was 4.8 $\mu g/m^3$.

Since the San Diego air basin is non-attainment for the state PM_{10} 24 hr standard, additional analysis was performed to determine whether or not additional violations would occur as a result of the proposed entire facility operation. For this additional analysis six days were identified at the Escondido monitoring station for the 3-year period modeled with background concentrations between 45 and 50 $\mu g/m^3$. The modeling for this additional analysis was conducted as described above. The maximum predicted 24 hr impact for any of the six days was 0.23 $\mu g/m^3$, which when added to the six days in question's background concentration, would not cause an additional exceedance of the state 24 hr standard. If the emission from the entire facility were doubled for this analysis (which would include a 100% of TDS as PM_{10} assumption), doubling the estimated impact to .46 $\mu g/m^3$ an additional violation of the state 24 HR standard would still not result (See Table 6.3 of the DOC application.)

Rule20.3 (d)(3)-Prevention of Significant Deterioration (PSD)

This subsection requires that a PSD evaluation be performed for all contaminants that exceed PSD major source trigger levels. PSD is triggered for NO_2, CO, and PM_{10}. An analysis of the potential project impacts with respect to the PSD Class I increments was performed. There are two Class I areas (Agua Tibia and San Jacinto Wilderness Areas) within 62 miles (100-km) of the Palomar site. The locations of these areas with respect to the project are shown in Figure 6-1 of Appendix A.

The AERMOD model was used to conduct the PSD Class I air quality analysis at Agua Tibia Wilderness Area (within 50 km) since all receptor elevations are above stack height.
The CALPUFF model was used to conduct the PSD Class I air quality analysis at the San Jacinto Wilderness Area which is greater than 50 km from the project location.

1. Notifications

   The Federal Land Manger was sent a copy of the application for DOC, which included all information and analyses required by this portion of the rule. Although verbal contact was made, the District did not receive any formal comments from the Federal Land Manager.

2. Non-Criteria Pollutant Emissions

   It is not expected that there will be significant emissions of any non-criteria pollutants (see Rule 20.1 Table 20.1-8) from this project.

3. Air Quality Increment

   A significant impact analysis and air quality increment analysis were performed by ENSR International and reviewed by the District. These analyses were performed as required by PSD regulations and District Rule 20.3(d)(3)(iv). Predicted criteria pollutant impacts for all Class I and Class II areas were below PSD significant impact levels. Because predicted impacts were below significance levels no impact areas are defined and no further increment analysis is required under PSD. Nevertheless an analysis was completed and the results are provided in Tables 4a and 4b below.

Table 4a

Significant Impact and Class II PSD Increment Results

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Significant Impact Level ($\mu g/m^3$)	Class II Increment ($\mu g/m^3$)
NO_2	Annual	0.7	1	25
PM_{10}	Annual	0.8	1	17
	24-hour	4.8	5	30

SO_2	Annual	0.2	1	20
	24-hour	1.4	5	91
	3-hour	5.4	25	512
CO	8-hour	10.6	500	--[a]
	1-hour	30.1	2,000	--[a]
[a] PSD increments have not been enacted for CO by the Federal Clean Air Act				

Table 4b

Significant Impact and Class I PSD Increment Results

Pollutant	Averaging Period	Agua Tibia Maximum Modeled Impact (μg/m³)	San Jacinto Maximum Modeled Impact (μg/m³)	Proposed Class I Area Significant Impact Levels[a] (μg/m³)	Class I Area Increment (μg/m³)
SO_2	Annual 24-hour 3-hour	0.002 0.027 0.170	0.005 0.040 0.138	0.1 0.2 1.0	20 91 512
PM_{10}	Annual 24-hour	0.005 0.091	0.018 0.139	0.2 0.3	17 30
NO_2	Annual	0.006	0.008	0.1	25
a. Source: EPA proposed New Source Review reform, FR 7/23/96.					

4. Growth:

   California Independent System Operator (ISO) projected a shortage of 200 MW-300 MW of imported power in 2001. More recent projections are not able to assure there will be adequate power in the near future. ISO states while their 2002 Summer Assessment indicates that adequate resources will be available to meet the 2002 summer peak, there is concern that the existing surplus capacity (i.e. operating margins) may evaporate over the next few years. Also numerous generation projects planned for completion in the next few years have been cancelled or delayed. In addition, the ISO anticipates that several older generating units will be retired and additional capacity may be lost as environmental regulations become more restrictive. To maintain comparable operating margins in future years, the ISO anticipates that net generation capacity additions of 1,000 to 1500 MW/year will be necessary. The construction of this plant is in response to San Diego's need for additional electrical supply and the CEC's Electricity Report (ER 96) anticipated this need. Therefore, because the project is being constructed in response to projected growth in San Diego, no projected growth due to the presence of the additional power available from this facility was analyzed.

The applicant analyzed the socioeconomic impacts this project would have on the immediate area (see Section 5.8 of the Application for Certification), including the growth effects on population, employment and the economy. The District has reviewed the applicant's analysis and agrees that the project will not cause any significant residential, commercial, or industrial growth. Therefore, any air quality impacts due to this growth would likewise be insignificant. The applicant's analyses are summarized below.

Residential:

Construction workers must commute to changing job locations, and the job sites are not often near their homes. Construction workers who live in communities at distances greater than about a two-hour one-way commute tend to relocate to the vicinity of the construction site for the workweek, then return to their home on the weekend. Because of the size of the work force in San Diego County, it is considered likely that about 90% of project's construction jobs will be filled by workers commuting daily from within San Diego County. The numbers of workers required by craft for project construction compared to the total projected number of workers in these crafts will be insignificant based on applicant analyses presented in the Application for Certification Section 5.8.2.1.

Since the vast majority of construction workers already live in San Diego County and are expected to commute from their current residences, it is expected that the construction of this project will not result in an increase in workers relocating in the City of Escondido or other nearby communities.

Commercial: Because very few, if any, relocations are expected from the construction of this facility, there is no expected increase in the number of permanent new support jobs due to the construction of this facility. Also, because the generated power will be sold to the grid, there will be very little, if any, associated commercial growth directly due to the construction of this facility.

Industrial: Because this project is to generate power to be sold to the grid in response to a projected need in San Diego County, construction of this power plant is not expected to cause secondary industrial growth.

5. Soils and Vegetation:

The applicant has provided an analysis of the impacts on soil and vegetation within the vicinity of the plant. It is located in Section 5.2.3 of the Application for Certification (AFC) submitted to the CEC. The analysis includes the Agua Tibia and the San Jacinto Class I Areas.

From the US Forest Service document entitled " Guidelines for Evaluating Air Pollution Impacts on Class I Wilderness Areas in California", no injury to plant species are expected if the NOx concentration (24-hr annual mean) does not exceed 15 ppb (maximum) and the SOx concentration does not exceed 40 ppb (maximum) or 8 ppb (annual average). Additionally, the document states that any adverse effects of sulfur deposition is highly unlikely at 5 kg/ha/yr (ha: hectares) and total nitrogen deposition will not cause injury at less than 3 kg /ha/yr. Given the very low level of sulfur dioxide emissions from the proposed project, there will not be any measurable impact in either the Agua Tibia or the San Jacinto Wilderness Areas.
Since no data are available to quantify existing ambient levels of nitrogen dioxide in the Agua Tibia Wilderness Area, a receptor was included in the dispersion modeling corresponding to the point along the Agua Tibia Wilderness Area boundary closest to the proposed project. The modeling predicts a one-hour and annual nitrogen dioxide increase of 0.63 ppb and 0.02 ppb respectively, at the receptor. A similar analysis was performed for the San Jacinto Wilderness Area. The modeling predicted an

annual average nitrogen dioxide increase of 0.005 ppb. Given these results, potential impacts to soil and vegetation in the San Jacinto and Agua Tibia Wilderness Areas are expected to be insignificant.

6. Air Quality Related Value (AQRV) Impacts-Visibility-Plume Blight

   PSD regulations require an assessment of visibility impairment attributable to the project in Class I areas within 100 kilometers of the project location. There are two types of visibility degradation that must be evaluated; plume blight and regional haze. Plume blight is caused when an observer is able to see a visible plume that reduces visual range when the observer looks along or through the plume. A plume blight analysis is required for Class I areas within 50 kilometers of the project, in this case the Agua Tibia National Wilderness Area.

   The first two levels for screening visibility impacts using VISCREEN at Agua Tibia Wilderness showed potential exceedances of the screening criteria for plume perceptibility and contrast. Therefore, a Level-3 plume visibility analysis was performed using the PLUVUE II model, which is recommended by EPA (1992). The results of the analysis indicate that all modeled values of plume perceptibility (ΔE) and contrast (C_p) are well below the screening thresholds of 2.0 and +/- 0.05, respectively (EPA, 1992).

7. Air Quality Related Value (AQRV) Impact- Regional Haze

   A regional haze analysis is required for all Class I areas more than 50 km but less than 100 km of the project location. Regional haze is caused by the uniform particulate loading of the atmosphere that contributes to the attenuation of light. Beyond 50 km it is assumed that individual plumes have lost their coherence and the pollutants from the plume, including secondary aerosols, contribute to the general background loading of fine particulate matter. The CALPUFF model was used for this analysis with regionally representative meteorological data. The results of the regional haze analysis are summarized in Table 5. As shown in the table, the maximum extinction change from the background never exceeds five percent. A five percent change in extinction coefficient is generally considered the lowest perceptible change, and is used as a significance threshold for visibility impacts. Thus, the Palomar Energy project will not have an adverse regional haze impact.

Table 5

Maximum 24-Hour Average Regional Haze Impacts on San Jacinto Wilderness Area

Model Year	Maximum Extinction Change from Background (%)	Number of Days Maximum Change from Background is > 5%
1986	2.61	0
1987	2.21	0
1988	3.02	0
1989	3.19	0
1990	2.77	0

8. Air Quality Related Value (AQRV) Impacts- Acid Deposition:

Based on information presented on the USFS website, both Agua Tibia and San Jacinto Wilderness Areas have an AQRV associated with aquatic resources. NO_x and SO_2 emissions can affect aquatic resources through nitrogen and sulfur deposition.

The CALPUFF model is generally used to determine the potential for impacts from acid deposition in Class I areas. CALPUFF screening modeling provided upper-limit estimates of annual (wet and dry) deposition of sulfur and nitrogen compounds (computed as kilograms per hectare per year (kg/ha/yr)) associated with Palomar Energy Project emissions of SO_2 and NO_x.

No regulatory thresholds for acid deposition have been established for Class I Areas. Acid deposition impacts modeled by the applicant are more than two orders of magnitude below the minimum detectable limit for wet deposition (0.5 kg/ha/yr), and more than an order of magnitude below the conservative USFS significance threshold of 0.05 kg/ha/yr. Values for nitrogen are below the Deposition Analysis Threshold (DAT) of 0.005 kg/ha/yr being developed for Western Class I areas (FLAG, 2001). A DAT for sulfur has not yet been developed. Since increased nitrogen and sulfur deposition due to the proposed project will be insignificant, impacts to stream and river Acid Neutralization Capacity (ANC) and pH, and therefore acidification and/or eutrophication, are not likely to occur.

9. Stack Height Requirements:

   The Good Engineering Practice (GEP) stack height for this project is 110 ft. Therefore, no consideration can be given in determining project impacts for stack heights greater than 110 feet above site elevation. Building downwash was included in the air quality impact modeling analysis. This downwash was taken into account using the EPA Building Profile input program. No stack damper is proposed for this project.

10. Preconstruction Monitoring

    The District has ambient air quality monitoring stations in the Escondido area and at the Miramar Naval Air Station. The District has concluded that the data gathered at the Escondido station and Miramar Naval Air Station are representative of the background air quality for the proposed project area. The meteorological data gathered at these stations was used in the air quality impact modeling analyses.

    From the review of the submitted modeling and associated results contained in the Application for DOC dated November 27, 2001, operation of the proposed Palomar Energy generating facility will be in compliance with all New Source Review (NSR) and Prevention of Significant Deterioration (PSD) requirements with regard to impact thresholds and additional project impact analysis requirements for all Class I and II areas.

Rule 20.3(d)(3)(iii) and (4) – Public Notice and Comment:

These portions of the rule require the District to publish a notice of the proposed action in at least one newspaper of general circulation in San Diego County as well as send notices and specified documents to the EPA, ARB and the South Coast and Imperial County air districts. The District provided the required 30 days for public comments.

Comments on the PDOC were received from the ARB, CEC, EPA and the Applicant. All comments were considered in the issuance of this Final DOC. As a result of the comments and further information researched by the District, the BACT/LAER limit for NOx was revised to 2.0 ppm on a 1-hour average, except that the limit will be 2.0 ppm on a 3-hour average during any clock hour when duct firing occurs or when the difference between the maximum MW produced by the generator train and the minimum MW produced by the generator train exceeds + 25 MW. Also, because 24.3 tons of additional offsets need to be identified to cover the project's full potential to emit, a NOx emissions cap is included in the required conditions until such time as sufficient ERCs are secured. Other revisions and clarifications were also made in preparing this FDOC.

Rule 20.3(d)(5)-Emission Offsets

This portion of the rule requires that emissions of any federal non-attainment criteria pollutant or its precursors which exceed new major source thresholds be offset with actual emission reductions. Of the six criteria pollutants, ozone, nitrogen dioxide, carbon monoxide, sulfur dioxide, particulate matter with a diameter of 10 microns or less, and lead, the District is a federal non-attainment area only for ozone. Therefore, offsets are potentially only required for NOx and VOC emissions, as ozone precursors. However, VOC emissions are expected to be below major source levels (50 tons/yr). Therefore, offsets are only required for NOx emissions. With a maximum NOx potential to emit of 124.4 tons per year for this project, and because an offset ratio of 1.2 to 1 is required [Rule 20.3(d)(8(i)(B)] a total of 149.3 tons of NOx emission offsets will be required at startup.

Offsets may be actual emission reductions, stationary source Class A emission reduction credits (ERCs) issued under District Rules 26.0-26.10, or mobile source emission reduction credits (MERCs) issued under District Rule 27 (if approved by ARB and EPA.)

As of December 2002, the applicant is in possession of, or has taken options for, stationary source Class A ERCs representing 68.7 tons/yr of NOx credits and 37.5 tons per year of VOC credits. This is equivalent to 87.5 tons of NOx credits because VOC ERCs may be substituted for NOx at a ratio of 2:1. The applicant has identified and is in negotiation for another 38.5 tons of NOx credits and has identified 23.4 tons/yr available NOx credit. However, because the remaining 23.4 tons/yr of NOx credits have not been identified to the District, the FDOC will contain a condition to limit the Palomar project to a maximum annual NOx potential to emit of 105 tons/yr, corresponding to confirmed emission offsets of 126 tons/yr. This emissions cap can be increased to the total 124.4 tons/yr when sufficient emissions offsets (149.3 tons/yr) in compliance with District rules have been identified and secured, or provided to the District.

The table below summarizes the NOx offsets proposed for the facility. More details of the offset package are available in the application which is available for public review.

Offset Summary

1. Purchased ERC's

ERC Name	ERC Certificate NO.	NOx-Equivalent Amount Tons per year	Source
Sempra Energy Resources	000111-01	17.5	*Combustion turbine shutdown*
SER	000111-02	0.15 (from 0.3 tpy VOC)	*Combustion turbine shutdown*
SER	010228-01	7.6 from 15.2 tpy VOC)	*Process modification*
SER	921291-01	*20.8*	*Combustion turbine shutdown*
SER	921291-02	0.5 from 1.0 tpy of VOC	*Combustion turbine shutdown*
SER (formerly Vision Systems)	976993-01	10.5 (from 21.0 tpy of VOC)	*Partial shutdown of coating facility*
SER (formerly NRG)	020130-02	3.6	*Combustion engine shutdown*
Naverus	No ERC yet Under contract.	26.8	*Diesel engine replacement*
	Total	**87.5**	

2 *Negotiating*

ERC Name	**ERC Certificate No.**	**NOx-equivalent Amount Tons per year**	**Source**
Sempra Energy Solutions	Contract exchanged ERC application to be submitted	38.5	Boiler equipment replacement
	Total	*38.5*	

Rule 20.3 (e)(1) – Compliance Certification

This rule requires that prior to receiving an Authority to Construct (or Determination of Compliance), an applicant for any new or modified stationary source required to satisfy the LAER provisions of Subsection (d)(1) or the major source offset requirement of Subsection (d)(8) shall certify that all major sources operated by such person in the state are in compliance with all applicable emissions limitations and standards under the federal Clean Air Act. The applicant has stated that neither Palomar Energy, LLC, nor Sempra Energy Resources currently operate any facilities within California which are major stationary sources.

RULE 20.3(e)(2) – Alternative Siting and Alternatives Analysis

The applicant has provided an analysis of various alternatives to the project in the AFC. This analysis included a No Project alternative, alternative sites, and alternative technologies. Since all of San Diego County is currently classified as non-attainment for ozone, an alternative location within San Diego would not avoid the project being located in a non-attainment area.

Rule 20.5 – Power Plants:

This rule requires that the District submit Preliminary and Final Determinations of Compliance reports to the California Energy Commission (CEC). The Final Determination of Compliance is equivalent to a District Authority to Construct.

The District submitted a Preliminary Determination of Compliance to the Commission on July 3, 2002. This subsequent document contains the Final Determination of Compliance. The District has considered comments received on its Preliminary Determination of Compliance and additional analyses by the District and applicant in reaching its decision to issue this Final Determination of Compliance.

Rule 50 – Visible Emissions:

This rule limits air contaminants emissions into the atmosphere of shade darker than Ringelmann 1 (20% opacity) to not more than an aggregate of three minutes in any consecutive sixty-minute period.

Based on the proposed equipment and the type of fuel to be used, no visible emissions at or above this level are expected during operation of the power plant. Except for the presence of water plume no visible emissions are expected from the cooling towers.

Rule 51 – Nuisance:

This rule prohibits the discharge of air contaminants that cause or have a tendency to cause injury, nuisance, annoyance to people and/or the public or damage to any business or property.

No nuisance or complaints are expected from this equipment.

Rule 53 – Specific Air Contaminants:

This rule limits emissions of sulfur compounds (calculated as SO_2) to less than or equal to 0.05% by volume, on a dry basis. The rule also limits particulate matter emissions from gaseous fuel combustion to less than or equal 0.1 grains per dry standard cubic foot of exhaust calculated at 12% CO_2.

Sulfur Compounds

The applicant proposes to use Public Utilities Commission (PUC) quality natural gas sold in San Diego County. Because of the low sulfur content of the fuel, the plant is expected to comply with the sulfur emission requirements of Rule 53. The fuel is expected to have a sulfur content less than 0.75 grains per 100 dry standard cubic foot (gr/dscf).

Particulates

Assuming an F-Factor of 198.025 standard cubic feet of exhaust per pound of fuel combusted @ 12% CO_2, a maximum natural gas usage of 76,544 lbs /hr, and an estimated maximum particulate matter emission rate of 14.0 lbs/hr, combustion particulate at maximum load are estimated to be:

Grain loading = [(14.0 lbs/hr)(7,000 gr/lb)] / (15.15 E6) = 0.00647 gr/dscf

This is well below the Rule 53 emission limit of 0.1 gr/dscf. Therefore the plant is expected comply with this rule.

Rule 68 –Oxides of Nitrogen from Fuel Burning Equipment:

This rule limits NOx emissions from any fuel burning equipment to less than 125 ppmv calculated at 3% oxygen on a dry basis.

However, since this equipment is subject to the more stringent requirements of Rule 69.3.1, the equipment is exempt from Rule 68.

Rule 69.3-Stationary Gas Turbines – Reasonably Available Control Technology:

This rule limits NOx emissions from gas turbines greater than 0.3 MW to 42 ppm at 15% oxygen when fired on natural gas. The rule also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits.

The proposed turbines for this project will be equipped with dry low NOx combustors and SCR controls for NOx. Emissions are expected to be far below 42 ppm. The facility permit will contain conditions to limit emissions below the emissions levels specified in Rule 69.3.1(excluding startups). Therefore, since those limits are more stringent than the 42 ppm limit, compliance with this rule is expected.

<u>Rule 69.3.1 – Stationary Gas Turbines – Best Available Retrofit Control Technology:</u>
This rule limits NOx emissions from gas turbines greater than 10 MW to 15x(E/25) ppm when operating uncontrolled and 9 x (E/25) ppm at 15% oxygen when operating with controls and averaged over a 1-hour period. E is the thermal efficiency of the unit. The rule also specifies monitoring and record keeping requirements. Startups, shutdowns, and fuel changes are defined by the rule and excluded from compliance with these limits. Maximum durations of startups have been proposed by the applicant.

The thermal efficiency for each turbine, as stated by the applicant, is 32.7%. Therefore the maximum allowable uncontrolled NOx concentration is 19.6 ppmv based on 1-hr averaging period at 15% oxygen and the maximum allowable controlled NOx concentration is 11.8 ppmvd. The proposed turbines for this project will be equipped with dry low NOx combustors and SCR controls for NOx. Emissions are expected to be far below 11.8 ppmvd. The facility permit will contain conditions to limit emissions below these levels (excluding startups and shutdowns). A portable CEMS will measure emissions during commissioning if permanent CEMS are not yet available.

Emissions above these levels during the Commissioning Period could occur during shakedown and testing of the turbines and control equipment. Emission excursions above these levels during the Commissioning Period are not authorized under the current rule. If these limits are exceeded, the applicant has been advised that a temporary variance from this rule may be necessary during this period. Once the control equipment has been installed and commissioned, this equipment is expected to comply with these limits.

Rule 1200 – Toxic Air Contaminants

Rule 1200 New Source Review for Toxic Air Contaminants requires that a Health Risk Assessment (HRA) be performed if the emissions of toxic air contaminants will increase. A detailed HRA is necessary if toxics emissions exceed District de minimis levels. Toxic Best Available Control Technology (TBACT) must be installed if the HRA shows a cancer risk greater than one in a million. Additional requirements apply if the cancer risk is expected to exceed ten in a million.

An HRA was performed using California Air Toxics Emission Factors (CATEF) for all toxics from the combined-cycle systems. The HRA conservatively assumed a 50% control efficiency for the oxidation catalyst. Under these assumptions, the health risk was determined to be less than one in a million at all the receptors located beyond the plant boundary. The heath risk analysis of this project is discussed in Appendix B of this document.

To verify the emissions from the combined-cycle systems used in the HRA, source testing will be performed. The source test will speciate emissions for the following air toxics: acetaldehyde, acrolein, benzene, formaldehyde, toluene and xylenes. In the development of the Combustion Turbines MACT Standard, EPA has determined that formaldehyde will represent about 80% of the mass emissions of toxics from a gas turbine. The other toxics are generally expected to be below or near method detection limits.

The Applicant's HRA and subsequent supplemental HRA also addressed potential air toxic emissions associated with use of reclaimed water in the cooling tower. The analyses provided by the Applicant identifies the compounds that will occur in the water, the reductions of these compounds that will occur once tertiary treatment systems at the HARRF are operational, the emission rates and health risks of these compounds, and ambient air quality impacts. After review, the District has determined that toxic air contaminant emissions from the cooling tower will not cause a significant health risk, and will not cause overall project risks to be above 1 in a million.

VI. ENDANGERED SPECIES ACT

Two species which are listed species of concern under the Endangered Species Act (ESA) are known to live in the vicinity of the project: the Western Spade foot toad and the California Gnatcatcher. Pursuant to Section 7 of the ESA and implementing regulations at 50 CFR Part 402, EPA is required to initiate consultation with the federal Fish and Wildlife Service (FWS) and/or the National Marine Fisheries Service (NMFS) if any action it authorizes, funds, or carries out may affect any species listed as endangered or threatened or designated critical habitat. Although the authority to issue the federal PSD permit has been delegated to the District, the EPA retains its responsibilities to ensure that PSD permitting actions are not likely to jeopardize the continued existence of endangered species, or adversely affect their critical habitats.

When a Federal action involves more than one agency, consultation and conference responsibilities may be fulfilled through a lead agency. The EPA may have responsibilities under Section 7 of the ESA for this project.

The applicant has stated a draft Biological Assessment for the Escondido Research and Technology Center (ERTC) industrial park was submitted to the U.S. Army Corps of Engineers (Corps) and the FWS. This submittal requests that the Corps initiate a consultation pursuant to Section 7 of the ESA with the FWS concerning whether construction or operation of the ERTC would jeopardize the continued existence of any endangered or threatened species. The power plant will be constructed on a building site after initial grading of the entire ERTC area. It is expected that compliance with the ESA regarding construction impacts will therefore be undertaken through a Section 7 consultation between the Corps and FWS. The FWS may issue a finding of no impact with regards to the project. If the FWS comes to a different conclusion, a different process will result and EPA may specify reasonable and prudent measures and terms and conditions necessary and appropriate to minimize such impact. The District cannot issue a final PSD permit until all ESA requirements have been addressed. When EPA has determined that relevant obligations under the ESA have been satisfied, the District will issue a supplement to this FDOC as the final PSD permit. The appeal period for terms and conditions of the permit that are necessary for PSD purposes will then be initiated pursuant to 40 CFR Part 124.

VII. ADDITIONAL ISSUES

Commissioning Period:

After construction of the equipment has been completed, the applicant will be allowed a commissioning period of 120 days. If problems arise, the applicant may request an extension, in writing, for District approval. This request must include all technical reasons why the extension is needed. Any extension will not exceed an additional 30 days. The District will approve the extension if technically justified and:

(a) is not the result of neglect or disregard of any air pollution control requirement;
(b) is not intentional or the result of negligence, as defined in District Rule 98;
(c) is not the result of improper maintenance;
(d) will not cause a nuisance;
(e) is not likely to create an immediate threat or hazard to public health or safety;
(f) will not interfere with the attainment or maintenance of any National or California Ambient Air Quality Standard; and
(g) good cause is shown for the extension.

During the 120-day commissioning period, the turbines will go through shakedown testing and tuning to ensure that the equipment is working properly and will be able to comply with all the proposed emission limits. However, during the initial startup, certain emissions standards must remain in effect. These include the 124.4 tons/yr limit (105 tpy until sufficient emissions offsets are provided to cover the full potential to emit) for NOx, the hourly mass emission limits for NOx and CO to ensure there will be no violation of any state or national ambient air quality standards, and the hourly concentration limits for NOx and CO to ensure compliance with the District RACT and BARCT Rules 69.3 and 69.3.1, respectively. If the permanent CEMS are not functional at the time of initial startup, the applicant will be required to use a portable CEMS unit which has been calibrated to monitor initial startup of the turbines.

Once the emissions control equipment has been installed and is in good working order, the turbines must meet all BACT/LAER standards and permit requirements. CEMS and source testing will be used to show compliance with these standards.

CONCLUSIONS AND RECOMMENDATIONS

A Determination of Compliance confers the same rights and privileges as an Authority to Construct only when and if the California Energy Commission (CEC) approves the Application For Certification, and the CEC certificate includes all conditions of the Determination of Compliance as proposed by the Air Pollution Control Officer.

If operated in accordance with the conditions specified in this Final Determination of Compliance, this equipment is expected to operate in compliance with all Rules and Regulations of the San Diego County Air Pollution Control District.

Original Signed by **Evariste Haury** 12/6/2002

Project Engineer Date

for

Original Signed by **Daniel A. Speer** 12/6/02

Senior Engineer Approval Date

VIII. PROPOSED PERMIT CONDITIONS

GENERAL CONDITIONS

1. Operation of this equipment shall be conducted in accordance with all data and specifications submitted with the application under which this permit is issued unless otherwise noted below.

2. This equipment shall be properly maintained and kept in good operating condition at all times.

3. The permittee shall provide access, facilities, utilities, and any necessary safety equipment for source testing and inspection upon request of the Air Pollution Control District.

4. The permittee shall obtain any necessary District permits and CEC approval for all ancillary combustion equipment including emergency engines, prior to on-site delivery of the equipment.

5. The exhaust stacks for each turbine power station shall be at least 110 feet in height above site base elevation.

6. At least 90 days prior to the start of construction, the applicant shall submit to the District the final selection, design parameters and details of the selective catalytic reduction (SCR) and oxidation catalyst emission control systems. Such information may be submitted to the District as trade secret and confidential pursuant to District Rules 175 and 176.

7. The exhaust stacks for each turbine shall be equipped with source test ports and platforms to allow for the measurement and collection of stack gas samples consistent with all approved test protocols. The ports and platforms shall be constructed in accordance with District Method 3A, Figure 2, and approved by the District.

8. This equipment shall be fired on natural gas only. The sulfur content of the natural gas used shall not exceed 0.75 grains per 100 standard cubic feet of natural gas. The applicant shall maintain quarterly records of fuel content (grains of sulfur compounds per 100 scf of natural gas) and higher heating value (BTU/scf) and shall make these records available to District personnel upon request. Specifications, including sulfur content and higher heating value, of all natural gas, other than Public Utility Commission (PUC)-regulated natural gas, shall be submitted to the District for written approval prior to use.

9. A Continuous Emission Monitoring System (CEMS) shall be installed and calibrated to measure and record the concentration of NOx, CO, and O_2 in the exhaust gas on a dry basis (ppmvd). Upon initial start of operation, a properly installed and calibrated CEMS shall thereafter be in full operation at all times when the turbine is in operation. If needed prior to installation and approval of the permanent CEMS, a portable CEMS which has been properly calibrated, may be used to continuously measure and record these parameters. Within 90 days after the commencement of commercial operations (as defined by 40 CFR 72.2), the CEMS shall be certified.

10. At least 60 days prior to initial startup of the gas turbines, the applicant shall submit a protocol to the District, for written approval, that shows how the permanent CEMS will be able to meet all District monitoring requirements and measure NOx emissions at a level of 2.0 ppmv. For the purpose of this FDOC initial startup shall be define as the time when fuel is first fired in the equipment and shall not include the purging of foreign material from inside of the steam paths and from the outside of the tubes also known as steam blow / boilout.

11. At least 60 days prior to initial startup of the gas turbines, the applicant shall submit a protocol to the District for approval which shall specify a method of determining the CO/VOC surrogate relationship that shall be used to demonstrate compliance with all VOC emission limits.

12. Prior to initial startup, each turbine shall be equipped with continuous monitors to measure or calculate, and record, the following operational characteristics of each unit:

    natural gas flow rate (scfh),
    heat input rate (MMBtu /hr),
    exhaust gas flow rate (dscfm),
    exhaust gas temperature (°F), and
    power output (gross MW).
    natural gas flow rate of duct burners

    The monitors shall be installed, calibrated, and maintained in accordance with an approved protocol. This protocol, which shall include calculation methodology, shall be submitted to the District for written approval at least 60 days prior to the initial startup of the gas turbines. The monitors shall be in full operation at all times when the turbine is in operation.

13. All CEMS shall be certified, calibrated, maintained, and operated for the monitoring of NOx and CO in accordance with the applicable regulations including the requirements of Sections 75.10 and 75.12 of Title 40, Code of Federal Regulations Part 75 (40 CFR 75), the performance specifications of Appendix A of 40 CFR 75, the quality assurance procedures of Appendix B of CFR 75, and a CEMS protocol approved by the District. At least 60 days prior to the operation of the permanent CEMS, the applicant shall submit a CEMS operating protocol to the District for written approval.
14. The District shall be notified in writing at least two (2) weeks prior to any proposed changes to be made in any Continuous Emission Monitor (CEM) software which

affect the value of data displayed on the CEM monitors and recorded for reporting with respect to the parameters measured by their respective sensing devices.

15. A monitoring plan in conformance with 40 CFR 75.53 shall be submitted to EPA Region 9 and the District at least 45 days prior to the RATA test, as required in 40 CFR 75.62.

16. No later than 90 days after each unit commences commercial operation (commercial operation is defined as the instance when power is sold to the grid), a Relative Accuracy Test Audit (RATA) and other required certification tests shall be performed and completed on the CEMS in accordance with 40 CFR Part 75 Appendix A Specifications and Test Procedures. At least 60 days prior to the test date, the applicant shall submit a test protocol to the District for written approval. Additionally, the District shall be notified a minimum of 45 days prior to the test so that observers may be present. Within 30 days of completion of this test, a written test report shall be submitted to the District for approval.

17. The total aggregate emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide, from all emission units at this stationary source shall not exceed 105 tons for each rolling 12-calendar month period. Upon surrender of sufficient emission offsets in compliance with District Rules 20.1 and 20.3, the total aggregate NOx limit shall increase up to 124.4 tons for each rolling 12-calendar month period. These additional emission offsets must have been publicly noticed through the emission reduction credit banking process or in a California Energy Commission or District notification specific for this project.

    Aggregate Stationary source NOx emissions shall begin accruing at the first initial startup of either turbine. Compliance with the aggregate NOx limit shall be verified using the CEMS on each gas turbine as well as EPA- or ARB-certified NOx emission factors, testing results, or other representative emissions information for all other combustion equipment.

18. The total aggregate emissions of Volatile Organic Compounds (VOC) from all emission units at this stationary source shall not exceed 50 tons for each rolling 12-calendar month period. The VOC emissions shall begin accruing at the first initial startup of either turbine. Compliance with this limit shall be based on District-approved source testing and the District-approved CO/VOC surrogate relationship.

19. The applicant shall maintain records, on at least a calendar monthly basis, of total aggregate mass emissions of NOx and VOC, in tons per rolling 12-calendar month period, from all equipment, excluding permit exempt equipment, at this stationary source for the previous 12-month period. These records shall be maintained on site for a minimum of five years and made available to the District upon request.

20. Except during any period of time for which a variance from Rule 69.3.1 has been granted by the Air Pollution Control District Hearing Board, when operating with post-combustion air pollution control equipment, emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide, from each turbine shall not exceed 11.8 parts per million by volume on a dry basis (ppmvd) calculated over each 1-hour averaging period and corrected to 15% oxygen, excluding shutdowns, extended and regular startups. (Rule 69.3.1)

21. During shutdowns, and extended and regular startups, when operating with post-combustion air pollution control equipment, the total emissions from both turbines combined shall not exceed 200 pounds per hour of oxides of nitrogen (NOx), calculated as nitrogen dioxide and measured over each clock hour period. Additionally, when operating with post-combustion air pollution control equipment, the total emissions when only one turbine is in operation shall not exceed 100 pounds per hour of NOx, calculated as nitrogen dioxide and measured over each clock hour period. (Rule 20.3 (d)(2)(i)).

22. During extended startup and during shutdowns, when operating with post-combustion air pollution control equipment, the total emissions from both turbines combined shall not exceed 3,384 pounds per hour of carbon monoxide (CO), averaged over a 1-hour

averaging period. Additionally, when operating with post-combustion air pollution control equipment, the total emissions when one turbine is in operation shall not exceed 1,692 pounds per hour of CO over a 1-hour averaging period. (Rule 23(d)(2)(i)).

COMMISSIONING PERIOD CONDITIONS

23. Beginning at initial startup of each turbine, a "Commissioning Period" for each turbine shall commence. This Commissioning Period shall end 120 days after initial startup or immediately after written acceptance of clear custody and control of the equipment is turned over to the applicant, or after not more than 300 hours of gas turbine operation whichever comes first. During the Commissioning Period, only the emission limits specified in Conditions Nos. 17, 18, 19, 20, 21, 24, 25, 26 and 27 shall apply.

24. When operating without any post-combustion air pollution control equipment, the total emissions from both turbines combined shall not exceed 900 pounds per hour of oxides of nitrogen (NOx), calculated as nitrogen dioxide and measured over each clock hour period. Additionally, when operating without any post-combustion air pollution control equipment, the total emissions when only one turbine is in operation shall not exceed 450 pounds per hour of NOx, calculated as nitrogen dioxide and measured over each clock hour period. These emission limits shall apply during commissioning, shutdowns, transients and extended and regular startups. (Rule 20.3(d)(2)(i))

25. Within 120 days or 300 hours of gas turbine operation, whichever comes first, after initial startup of each turbine, the applicant shall install all required post-combustion air pollution control equipment. Once installed, the post-combustion air pollution control equipment shall be maintained in good condition and, with the exception of periods during startup and shutdown, shall be in full operation at all times when the turbine is in stable operation.

26. When operating without any post-combustion air pollution control equipment, the total emissions from both turbines combined shall not exceed 4,000 pounds per hour of carbon monoxide (CO), measured over each clock hour period. Additionally, when operating without any post-combustion air pollution control equipment, the total emissions when one turbine is in operation shall not exceed 2,000 pounds per hour of CO measured over each clock hour period. These emission limits shall apply during commissioning, shutdowns, transients and startups. (Rule 23(d)(2)(i))

27. Except during any period of time for which a variance from Rule 69.3.1 has been granted by the Air Pollution District Hearing Board, when operating without any post-combustion air pollution control equipment, the emissions of oxides of nitrogen (NOx), calculated as nitrogen dioxide, from each turbine shall not exceed 19.6 parts per million by volume on a dry basis (ppmvd) calculated over each 1-hour averaging period and corrected to 15% oxygen, excluding shutdowns, regular and extended startups. (Rule 69.3.1)

28. Within 30 days after the end of the Commissioning Period for each turbine, the applicant shall submit a written progress report to the District. This report shall include, at a minimum, the date the Commissioning period ended, the periods of startup, the emissions of NOx and CO during startup, and the emissions of NOx and CO during steady state operation with and without duct burner firing. NOx and CO emissions shall be reported in both ppmv at 15% O_2 and lbs/hr. This report shall also detail any turbine or emission control equipment malfunctions, upsets, repairs,

maintenance, modifications, or replacements affecting emissions of air contaminants that occurred during the Commissioning Period.

29. Before operating an SCR system, continuous monitors shall be installed on each SCR system to monitor or calculate, and record the following:

    ammonia injection rate (lbs/hr)

    SCR catalyst temperature (°F)

    The monitors shall be installed, calibrated, and maintained in accordance with an approved protocol. This protocol, which shall include any relevant calculation methodologies, shall be submitted to the District for written approval at least 60 days prior to initial startup of the gas turbines with the SCR system. The monitors shall be in full operation at all times when the turbine is in operation.

CONDITIONS FOR ON-GOING OPERATIONS

30. The period described as "on-going" operations of each turbine shall commence immediately following the end of the Commissioning Period for that turbine. Conditions Nos. 17, 18, 19, 20, 21, 24, 26, and 27 shall continue to apply during on-going operations.

31. Emissions of oxides of nitrogen (NOx) from each gas turbine/heat recovery steam generator train, as measured at the exhaust stack exit, calculated as nitrogen dioxide, shall not exceed 2.0 parts per million by volume on a dry basis (ppmvd) corrected to 15% oxygen. In determining compliance with this emission limitation, the following averaging periods shall apply:
    a. During any clock hour when duct firing is occurring (a "duct-fired hour"): 3-hour average, calculated as the average of the duct fired hour, the clock hour immediately prior to and the clock hour immediately following the duct-fired hour.
    b. During any clock hour when the difference between the maximum MW produced by the generator train and the minimum MW produced by the generator train exceeds + 25 MW (a "transient hour"): 3-hour average, calculated as the average

of the transient hour, the clock hour immediately prior to and the clock hour immediately following the transient hour.

c. All other hours: 1-clock hour average.

Compliance with this limit shall be based on CEMS data for each unit averaged over each averaging period, or portions thereof, as applicable, excluding time when the equipment is operated under startup or shutdown conditions and time that the equipment is not in operation. Compliance with this limit shall also be verified through an initial source test and at least annual source testing thereafter.

32. The emissions of carbon monoxide (CO) from each turbine shall not exceed 4.0 parts per million by volume (3-hr rolling average) on a dry basis (ppmvd) corrected to 15 % oxygen. Compliance with this limit shall be based on CEMS data for each unit and averaged over each rolling 3-hour period or portion there of, excluding time when the equipment is operated under startup or shutdown conditions and time that the equipment is not in operation. Compliance with this limit shall also be verified through an initial emission source test and at least annual source testing thereafter.

33. The emissions of volatile organic compounds (VOC) from each turbine, calculated as methane, shall not exceed 2.0 parts per million by volume (3-hr average) on a dry basis (ppmvd) corrected to 15% oxygen. Compliance with this limit shall be based on District-approved source testing, and on the District-approved CO/VOC surrogate relationship and CO CEMS data for each unit averaged over each rolling 3-hour period or portion thereof, excluding time when the equipment is operated under startup or shutdown conditions and time the equipment is not in operation. The CO/VOC surrogate relationship shall be verified and/or modified, if necessary, based on initial emissions source tests and at least annual source testing thereafter.

34. The emissions of ammonia (ammonia slip) from each gas turbine exhaust stack following the SCR controls shall not exceed 10.0 parts per million by volume on a

dry basis (ppmvd) corrected to 15 % oxygen. Compliance with this limit shall be verified through an initial source test and at least annual source testing thereafter.

35. The maximum total dissolved solids (TDS) concentration of the reclaimed water to be used in the cooling towers shall not exceed 4,000 mg/l. This concentration shall be verified through quarterly testing of the reclaimed water.

36. When operating without the duct burner, the emissions from each turbine shall not exceed the following emission limits, except during startup or shutdown conditions, as determined by the CEMS and/or District approved emissions source testing. Compliance with the NOx limit shall be based on each rolling 1-hour averaging period or portion thereof, and compliance with CO and VOC limits shall be based on each rolling 3-hour averaging period or portion thereof.

Pollutant	Emission Limit, lbs/hr
Oxides of Nitrogen, NOx (calculated as NO_2)	13.4
Carbon Monoxide, CO	16.3
Volatile Organic Compounds, VOC	4.0

37. When operating with the duct burner, the emissions from each turbine shall not exceed the following emission limits, except during startup or shutdown conditions, as determined by the Continuous Emissions Monitoring System (CEMS) and continuous monitors and / or District approved emissions source testing. Compliance with the NOx, CO, and VOC limits shall be based on each rolling 3-hour averaging period.

Pollutant	Emission Limit, lbs/hr
Oxides of Nitrogen, NOx (calculated as NO_2)	14.9
Carbon Monoxide, CO	18.1
Volatile Organic Compounds, VOC	7.3

38. The maximum combined fuel input into the duct burners for both turbines shall not exceed 780,000 MMBtu per rolling 12-calendar month period. The applicant shall maintain a log that contains, at a minimum, the dates, times, and duct burner fuel consumption when one or both turbines are operated with the duct burners in operation. These logs shall be maintained on site for a minimum of five years and made available to District personnel upon request.

39. Extended startup is defined as the time necessary to reach minimum operating conditions for the air pollution control equipment and to meet the emission limits specified in conditions 31 and 32, not to exceed 4 hours, after initial startup of the turbine following a shutdown period of greater than or equal to 48 hours.

40. A regular startup is defined as the time necessary to reach minimum operating conditions for the air pollution control equipment and to meet the emission limits specified in conditions 31 and 32, not to exceed 2 hours in duration, after initial startup of the turbine following a shutdown period of less than 48 hours.

41. Shutdown is defined as the period beginning with the lowering of the output of a gas turbine below 50% of its base capacity and below the minimum operating conditions for the air pollution control equipment, and ending when combustion has ceased.

42. The emissions of particulate matter less than 10 microns (PM_{10}) shall not exceed 14.0 lbs/hr for each turbine with and without duct burner firing. Compliance with this limit shall be based on an initial emissions source test and at least annual source testing thereafter.

43. Within 30 days after completion of the Commissioning Period, an initial emissions source test shall be conducted by an independent, ARB approved tester at the applicant's expense to show compliance with all applicable emission limits. A source test protocol shall be submitted to the District for written approval at least 60 days

prior to source testing. The source test protocol shall comply with the following requirements:

a. Measurement of oxides of nitrogen (NOx), carbon monoxide (CO), and stack gas oxygen shall be conducted in accordance with the San Diego Air Pollution Control District Method 100, or equivalent, as approved by the Air Pollution Control Officer.

b. Measurements of particulate matter less than 10 microns shall be conducted in accordance with the U.S. Environmental Protection Agency (EPA) Methods 201A and 202, or equivalent, as approved by the Air Pollution Control Officer.

c. Measurements of volatile organic compounds (VOC) shall be conducted in accordance with San Diego Air Pollution Control District Methods 25A and /or 18, or equivalent as approved by the Air Pollution Control Officer.

d. Measurement of Ammonia emissions shall be conducted in accordance with BAAQMD.ST-1B, or equivalent as approved by the Air Pollution Control Officer.

e. Source testing shall be performed without duct burner firing at no less than 80% of the turbine base load operation, and with duct burner firing at no less than 80% of combined capacity.

44. Within 30 days after completion of the Commissioning Period, an initial emissions source test shall be conducted by an independent, ARB approved tester at the applicant's expense to determine the emissions of toxic air contaminants (TAC). A source test protocol shall be submitted to the District for written approval at least 60 days prior to source testing. The source test will not include testing of the cooling

towers. At a minimum, the following compounds shall be tested for and emissions, if any, quantified:

Acetaldehyde
Acrolein
Benzene
Formaldehyde
Toluene
Xylenes

This list of compounds to be tested may be adjusted by the District based on source test results to ensure that compliance with District Rule 1200 is demonstrated. The District may require one or more of these compounds, or additional compounds to be quantified through source testing periodically as needed to ensure compliance with Rule 1200.

45. Within 60 days after completion of the initial source tests, a final source test report shall be submitted to the District for review and approval. The testing contractor shall include, as part of the test report, a certification that to the best of its knowledge the report is a true and accurate representation of the test conducted and the results.

46. The District may require one or more of these compounds, or additional compounds to be quantified through source testing periodically as needed to ensure compliance with Rule 1200.

47. This equipment shall be source tested on at least an annual basis to show continued compliance with all applicable emissions limits, unless otherwise directed in writing by the District. An annual CEMS RATA, where required, may be used to fulfill the annual source testing requirement for NOx and CO. If the testing will be performed by someone other than the District, a source test protocol shall be submitted to the District for written approval at least 60 days prior to source testing. The source test protocol shall comply with the same requirements as listed in condition 43. Within 60 days after completion of testing, a final test report shall be submitted to the District for review and approval.

48. The emissions of any single federal hazardous air pollutant shall not equal or exceed 10 tons, and the aggregate emissions of all federal hazardous air pollutants, shall not equal or exceed 25 tons in any rolling 12-calendar month period. If emissions exceed these limits, the permittee shall apply to amend these limits and conduct a Maximum Achievable Control Technology (MACT) analysis in accordance with applicable federal EPA regulations. Compliance with this limit shall be based on District approved VOC/TAC and CO/VOC surrogate relationships and the result of District approved source testing.

49. Prior to the initial startup of this equipment, the applicant shall surrender to the District Class A Emission Reduction Credits (ERCs) in an amount equivalent to 126.0 tons per year of NOx to offset the maximum allowable of 105.0 tons per year of NOx emissions for this facility. When additional offsets are available up to 149.3 tons per year, maximum allowable emissions will increase to the maximum potential of 124.4 tons per year of NOx emissions.

ADDITIONAL GENERAL CONDITIONS

50. For each emission limit expressed as pounds per hour or parts per million based on a 1-hour averaging period, compliance shall be based on each rolling continuous 1-hour period using data collected at least once every 15 minutes when compliance is based on continuous emissions data.

51. For each emission limit expressed as pound per hour or parts per million based on a 3-hour averaging period, compliance shall be based on each rolling continuous 3-hour period using data collected at least once every 15 minutes when compliance is based on continuous emissions monitoring data.

52. All records required by this Authority to Construct shall be maintained on site for a minimum of five years and made available to the District upon request.

53. Pursuant to 40 CFR 72.30(b)(2)(ii) of the Federal Acid Rain Program, the applicant shall submit an application for a Title IV Operating Permit at least 24 months prior to the initial startup of this equipment.

54. The applicant shall comply with the continuous emission monitoring requirements of 40 CFR Part 75.

55. The applicant shall submit an application to the District for a Federal (Title V) Operating Permit, in accordance with District Regulation XIV, within 12 months after initial startup of this equipment.

ATTACHMENTS

APPROVAL OF AIR QUALITY IMPACT ANALYSIS (Modeling)
AND
PREVENTION OF SIGNIFICANT DETERIORATION REPORT

REVIEW OF HEALTH RISK ASSESSMENT

REVIEW OF SUPPLEMENTAL HEALTH RISK ASSESSMENT

AIR POLLUTION CONTROL DISTRICT RESPONSES TO PUBLIC COMMENTS ON THE PALOMAR ENERGY PROJECT PDOC

AIR QUALITY IMPACT AND PREVENTION OF SIGNIFICANT DETERIORATION FINAL REVIEW REPORT

PALOMAR ENERGY PROJECT
APPLICATION 976846

MAY 24, 2002

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1.0 INTRODUCTION

An Air Quality Impact Analysis (AQIA) and Prevention of Significant Deterioration (PSD) analysis was performed for the Palomar Energy Generating Project 560 MW natural gas-fired, combined cycle electric generating project by ENSR International for Palomar Energy LLC. In November 2001 an Application for Determination of Compliance (DOC) for the project, including the AQIA and PSD analysis, was submitted to the San Diego Air Pollution Control District (District). This submittal was reviewed and questions and comments regarding the dispersion modeling approach and results were provided to the Applicant. During subsequent meetings additional modeling requirements and procedures were agreed to by stakeholders.

This report focuses on the AQIA and PSD analysis results provided in the November 2001 submittal.

2.0 PROJECT DESCRIPTION

The Project is a natural gas–fired, combined cycle 560 MW power plant consisting of 2 GE 7FA gas combustion turbines with Dry-low NO_x combustors, 2 heat recovery steam generators (HRSG), 1 steam turbine generator(STG), 1 cooling tower and two (2) 110 foot high exhaust stacks . The Project facility is located in the City of Escondido, west of Interstate 15 and south of State Highway 78, about 600 feet southwest of the intersection of Vineyard Avenue and Enterprise Street. The applicant is proposing to use dry low- NO_x (DLN) and selective catalytic reduction (SCR) for post combustion NO_x control to a maximum of 2.0 ppmvd (3-hour average). CO (4.0 ppmvd 3-hour average), VOC (3.0 ppmvd 3-hour average) and HAP (50%) emissions will be controlled by an oxidation catalyst located within each HRSG.

3.0 EMISSION ESTIMATES

The facility (Both Turbines and Cooling Tower) annual potential to emit is as follows:

• Nitrogen oxides	124 tons per year
• Carbon monoxide	254 tons per year
• Sulfur dioxide	33 tons per year
• Particulate matter	105 tons per year
• Volatile organic compounds	47 tons per year

The facility (Both Turbines and Cooling Tower) maximum daily emissions are as follows:

• Nitrogen oxides	796 pounds per day
• Carbon monoxide	1720 pounds per day
• Sulfur dioxide	216 pounds per day
• Particulate matter	687 pounds per day
• Volatile organic compounds	392 pounds per day

The facility is a major stationary source and PSD source for Particulate Matter (PM_{10}), Nitrogen oxides (NO_x) and Carbon Monoxide (CO).

4.0 AIR QUALITY IMPACT ANALYSIS

Dispersion modeling was conducted for operational emissions of NO_2, CO, SO_2 and PM_{10}. The applicant and their consultant (ENSR International) worked closely with the District in developing modeling and analysis procedures in support of demonstrating compliance with all applicable NSR and PSD requirements.

The impact assessment was performed with respect to the ambient air quality in the project vicinity, the air quality in the Class I areas and the Air Quality Related Values (AQRVs) including visibility and acid deposition in the Class I areas.

In addition, during the commissioning and startup periods hourly emissions of CO and NO_x are expected to be much higher since the control system will not yet be optimized during the commissioning phase and not operating at optimum conditions during startups. CO and NO_x emissions were modeled to determine whether emissions during these time periods would impact the State and/or Federal Ambient Air Quality Standards for CO and NO_2.

These procedures are discussed in the following subsections.

4.1 MODELING METHODOLOGIES

Several different models were employed for the DOC dependent upon the receptor terrain, representative meteorological data availability, land class, stack heights relative to nearby building heights and recommended or proposed dispersion models. The following models were used:

- ISCST3 (Version 00101) for simple terrain receptors at or below stack height.
- AERMOD (Version 99351) for elevated terrain above stack height and for Agua Tibia Wilderness Area impacts (PSD increment).
- CALPUFF (Version 5.4 level 000602) for receptors located at the Agua Tibia (acid deposition only) and San Jacinto (PSD increment, visibility and acid deposition) Wilderness Areas.
- VISCREEN (Version 1.01) for visibility impacts at Agua Tibia Wilderness Area.
- PLUVUE II (Version 96170) for visibility impacts at Agua Tibia Wilderness Area.

4.2 METEOROLOGICAL DATA USED FOR DISPERSION MODELING

Meteorological data used for EPA's ISCST3 model consisted of following data for the 1998 through 2000 time period. The data was processed with MPRM to produce an ISCST3 ready file.

- Wind speed, wind direction, standard deviation of the horizontal wind direction and temperature from the District's Escondido monitoring station.
- Twice-daily upper-air soundings from Miramar, NAS.

- Cloud height and total opaque cloud amount from Miramar, NAS.

- Wind speed, wind direction and temperature data from Miramar, NAS for replacement of missing data in the Escondido data set.

Meteorological data used for EPA's AERMOD model consisted of the following data for the 1998 through 2000 time period. The data was processed with AERMET to produce an AERMOD ready file. Seasonal values for Albedo, Bowen Ratio (dry conditions), and Surface Roughness for the "desert shrubland" land classification (closest fit to the San Diego county chaparral vegetation) provided in Table 4-1 were input to the AERMET model.

- Wind speed, wind direction, standard deviation of the horizontal wind direction and temperature from the District's Escondido monitoring station.

- Twice-daily upper-air soundings from Miramar, NAS.

- Cloud height and total opaque cloud amount from Miramar, NAS.

- Wind speed, wind direction and temperature data from Miramar, NAS for replacement of missing data in the Escondido data set.

4-1
Table Seasonal Input Boundary Layer Parameters to AERMET

Parameter [a]	Spring	Summer	Autumn	Winter
Albedo	0.30	0.28	0.28	0.45
Daytime Bowen Ratio (Dry Conditions)	5.0	6.0	10.0	10.0
Surface Roughness	0.30	0.30	0.30	0.15
[a] AERMET User's Guide (EPA 1998) Tables 4-1 through 4-3 for desert shrubland				

Vertical temperature profiles for stable conditions (Class E and F) were set to those recommended by EPA and used as defaults in the ISCST3 model.

Five years of regionally representative meteorological data are required as input to CALPUFF run in screening mode. These data were collected during calendar years 1986-1990 in SAMSON format at San Diego Lindbergh Field. The EPA-approved meteorological pre-processor PCRAMMET (version 98226) was used to process the meteorological data into a format that the CALPUFF model accepts for the screening level analysis, including both wet and dry deposition parameters. Representative values of roughness length, albedo, Bowen ration, anthropogenic heat flux, precipitation and fraction of net radiation absorbed at the surface were required inputs to PCRAMMET and are shown (except precipitation) in Table 4-2 below.

Table 4-2
Input Boundary Layer Parameters to PCRAMMET

Parameter	Value
Minimum Monin-Obukhov Length	5.0 meters (mostly open land)
Anemometer height at surface station	6.1 meters
Surface roughness length, measurement site	0.15 meter (typical for NWS airport station)
Surface roughness length, application site	0.26 meter
Noon-time albedo	0.3275
Bowen ratio	7.75
Anthropogenic heat flux	0.0 W/m^2 (rural areas)
Fraction of net radiation absorbed by the ground	0.18 (mostly rural land use)

EPA's VISCREEN and PLUVUE II models are used to analyze visibility degradation for worst case dispersion conditions occurring within the three year (1998-2000) meteorological data set for Escondido/Miramar. The worst case plume dispersion meteorological conditions are used in a Level 1 VISCREEN screening analysis. The VISCREEN Level 2 analysis refines the analysis to include worst case meteorological conditions that occur at least 1 % of the time for wind directions that blow towards the Class I area. PLUVUE II (Level 3 analysis) simulates visible plume parameters for specific dates and times throughout the year when worst case meteorological conditions exist. 11 lines of site from a point east and a point west of the plume as it passes through the Class I area (Agua Tibia) were evaluated.

5.0 AIR QUALITY IMPACT ANALYSIS RESULTS

In accordance with EPA and San Diego Air Pollution Control District New Source Review Guidance and the modeling methodologies described above, maximum predicted concentrations and PSD increments associated with facility operations were determined for each criteria pollutant and the applicable averaging period during Normal, Startup and Commissioning conditions. The maximum predicted concentrations were added to worst-case background concentrations for comparison to Federal and State Ambient Air Quality Standards. Worst case background concentrations were determined from the review of 3 years (1998-2000) of monitoring data taken from the District's Escondido monitoring station, which was deemed to be most representative of air quality in the facility area. Table 5-1 summarizes the worst case background concentrations.

Table 5-1 Escondido Monitoring Station Maximum Observed Concentrations

Pollutant	Averaging Time	Units[a]	California Standards	Federal Standards	1998	1999	2000
Ozone	1-Hour	ppm ($\mu g/m^3$)	0.09 (180)	0.12 (235)	0.12 (235)	0.10 (196)	0.12 (235)
PM_{10}	24-Hour	$\mu g/m^3$	50	150	51.0	52.0	65.0
	Annual Arithmetic Mean	$\mu g/m^3$	None	50	20.5	30.0	29.6
	Annual Geometric Mean	$\mu g/m^3$	30	None	20.8	28.5	28.0
CO	1-Hour	ppm (mg/m^3)	20 (23)	35 (40)	10.2 (11.9)	9.9 (11.5)	9.3 (10.8)
	8-Hour	ppm (mg/m^3)	9 (10)	9 (10)	4.6 (5.3)	5.3 (6.1)	4.9 (5.6)
NO_2	1-Hour	ppm ($\mu g/m^3$)	0.25 (470)	None -	0.09 (172)	0.10 (191)	0.08 (153)
	Annual Average	ppm ($\mu g/m^3$)	None -	0.053 (100)	0.018 (34)	0.023 (43)	0.021 (40)

a. Concentrations given in the units reported and in parentheses when converted to different units based on a reference temperature of 20° C and a pressure of 760 mm of mercury, as required by the SDAPCD.

5.1 SIGNIFICANT IMPACT ANALYSIS AND CLASS II PSD INCREMENTS

Table 5-2 includes the results of the modeling analysis with respect to the Federal Significant Impact Levels (SILs) and PSD Class II increments during normal facility operations. Since all the results indicate impacts are below the SILs for criteria pollutants no further Class II increment analysis or Federal Ambient Air Quality Analysis (AAQS) is required, however the results are provided. All maximum impacts are below the Class II Increment levels. Table 5-3 provides information regarding the operating scenario (emission rate and release parameters) resulting in the predicted maximum impacts. Table 5-4 provides information regarding the location and Time/Date of the maximum impacts. Case numbers refer to 1 of the 12 modeling scenarios evaluated for the project. Complete details for each case are shown in Table C-1, Appendix C of the DOC. Figures 5-1 through 5-4 provide the locations of the maximum predicted impacts relative to the facility location.

Table 5-2 Significant Impact and Class II PSD Increment Results

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m³)	Significant Impact Level (μg/m³)	Class II Increment (μg/m³)
NO_2	Annual	0.7	1	25
PM_{10}	Annual	0.8	1	17
	24-hour	4.8	5	30
SO_2	Annual	0.2	1	20
	24-hour	1.4	5	91
	3-hour	5.4	25	512
CO	8-hour	10.6	500	--[a]
	1-hour	30.1	2,000	--[a]

[a] PSD increments have not been enacted for CO by the Federal Clean Air Act

Table 5-3 Modeling Parameters Used for Worst-Case Normal Operations Modeling [a]

Pollutant	Averaging Period	Stack Temp (K)	Exit Velocity (m/s)	Emission Rate (lb/hr/ turbine)	Operating Scenario
NO_2	1-hour	358.7	24.0	14.9	Case 4: 100% load with duct firing, 20-deg F ambient T
	Annual	358.7	24.0	14.9	Case 4: 100% load with duct firing, 20-deg F ambient T
SO_2	1-hour	358.7	24.0	4.5	Case 4: 100% load with duct firing, 20-deg F ambient T
	3-hour	358.7	24.0	4.5	Case 4: 100% load with duct firing, 20-deg F ambient T
	24-hour	358.7	24.0	4.5	Case 4: 100% load with duct firing, 20-deg F ambient T
	Annual	358.7	24.0	4.5	Case 4: 100% load with duct firing, 20-deg F ambient T
CO	1-hour	358.7	24.0	18.1	Case 4: 100% load with duct firing, 20-deg F ambient T
	8-hour	358.7	24.0	18.1	Case 4: 100% load with duct firing, 20-deg F ambient T
PM_{10}	24-hour	360.9	14.7	11.0	Case 9: 50% load without duct firing, 110-deg F ambient T
	Annual	360.9	14.7	11.0	Case 9: 50% load without duct firing, 110-deg F ambient T

[a] Turbine load conditions, stack parameters, and emission rates for all cases are provided in Table C-1 of the DOC Application

Table 5-4 Normal Operations Impact Location, Date/Time

Pollutant	Averaging Period	UTM Easting (m)	UTM Northing (m)	Project [a] Impact (mg/m^3)	Date/Time (yymmddhh)	Model	Turbine Case
NO_2 (1)	1-hour	486,200	3,663,150	24.8	99092203	AERMOD	4
	Annual	485,900	3,663,350	0.7	n/a	AERMOD	4
SO_2	1-hour	486,200	3,663,150	7.5	99092203	AERMOD	4
	3-hour	486,050	3,663,350	5.4	98022424	AERMOD	4
	24-hour	485,950	3,663,350	1.4	00110724	AERMOD	4
	Annual	485,900	3,663,350	0.2	n/a	AERMOD	4
CO	1-hour	486,200	3,663,150	30.1	99092203	AERMOD	4
	8-hour	485,800	3,663,750	10.6	00112108	AERMOD	4
PM_{10}	24-hour	486,050	3,663,350	4.8	00110724	AERMOD	9
	Annual	486,000	3,663,350	0.8	n/a	AERMOD	9

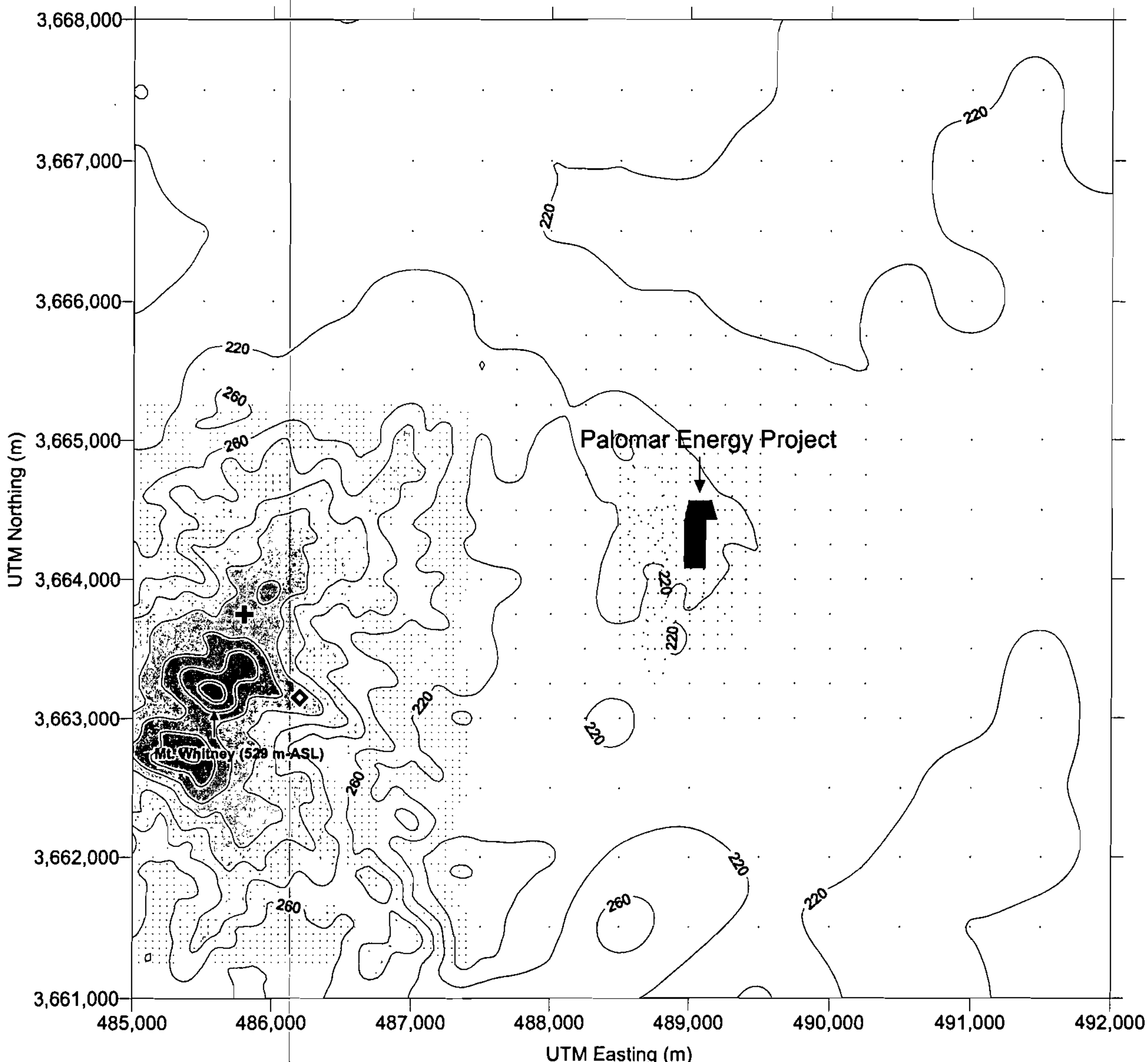
[a] Assumes 100% conversion of NO_x to NO_2

Table 5-5 provides project maximum impacts including worst case ambient background concentrations compared to Federal and California AAQS. The results demonstrate that normal facility operations will not cause or contribute to an exceedance of the National and California Ambient Air Quality Standards for NO_2, CO or SO_2.

Table 5-5 Maximum Ambient Air Quality Impact During Normal Operations

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Background ($\mu g/m^3$)	Total Impact [a] ($\mu g/m^3$)	Ambient Air Quality Standard [b]
NO_2	1-hour	24.8 [c]	191	216	470
	Annual	0.7 [c]	44	45	100
CO	1-hour	30.1	11,870	11,900	23,000
	8-hour	10.6	6,123	6,034	10,000
SO_2	1-hour	7.5	397	405	655
	3-hour	5.4	397	402	1300
	24-hour	1.4	53	54	105
	Annual	0.2	8	8.2	80
PM_{10}	24-hour	4.8	65	69.8	50
	Annual	0.8	28.5	29.3	30

[a] All total impacts rounded to three or fewer significant figures.
[b] Most stringent of Federal or California ambient air quality standard for each pollutant and averaging period.
[c] Assumes 100 percent conversion of NO_x to NO_2.



+ = 8-hr CO (Project Impact = 10.6, Significant Impact Level = 500)

◇ = 1-hr CO (Project Impact = 30.1, Significant Impact Level = 2000)

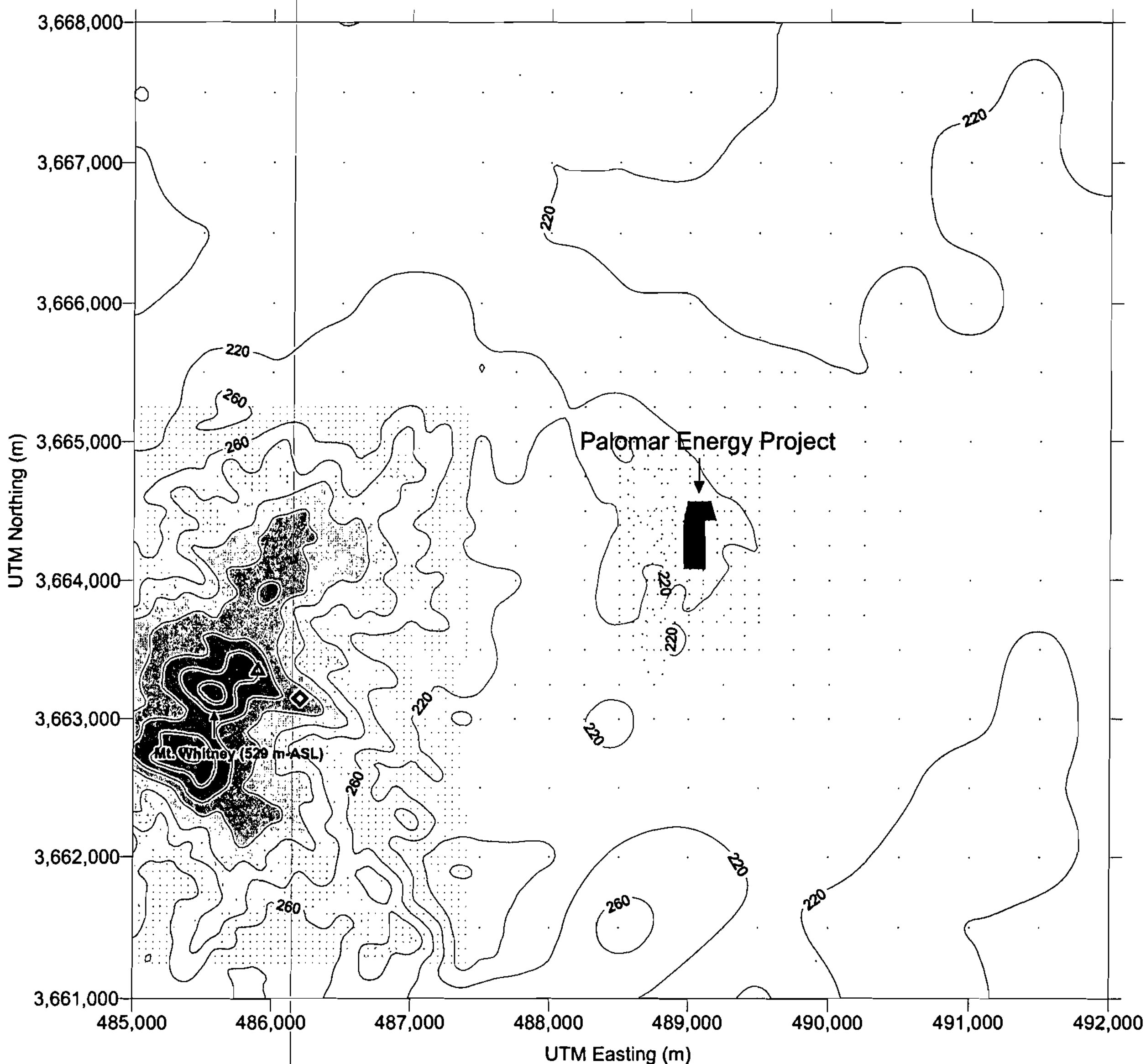
Figure 5-1

Palomar Energy Project: DOC Application No. 976846

Maximum Modeled CO Impact Locations During Normal Operations (Table 5-5)

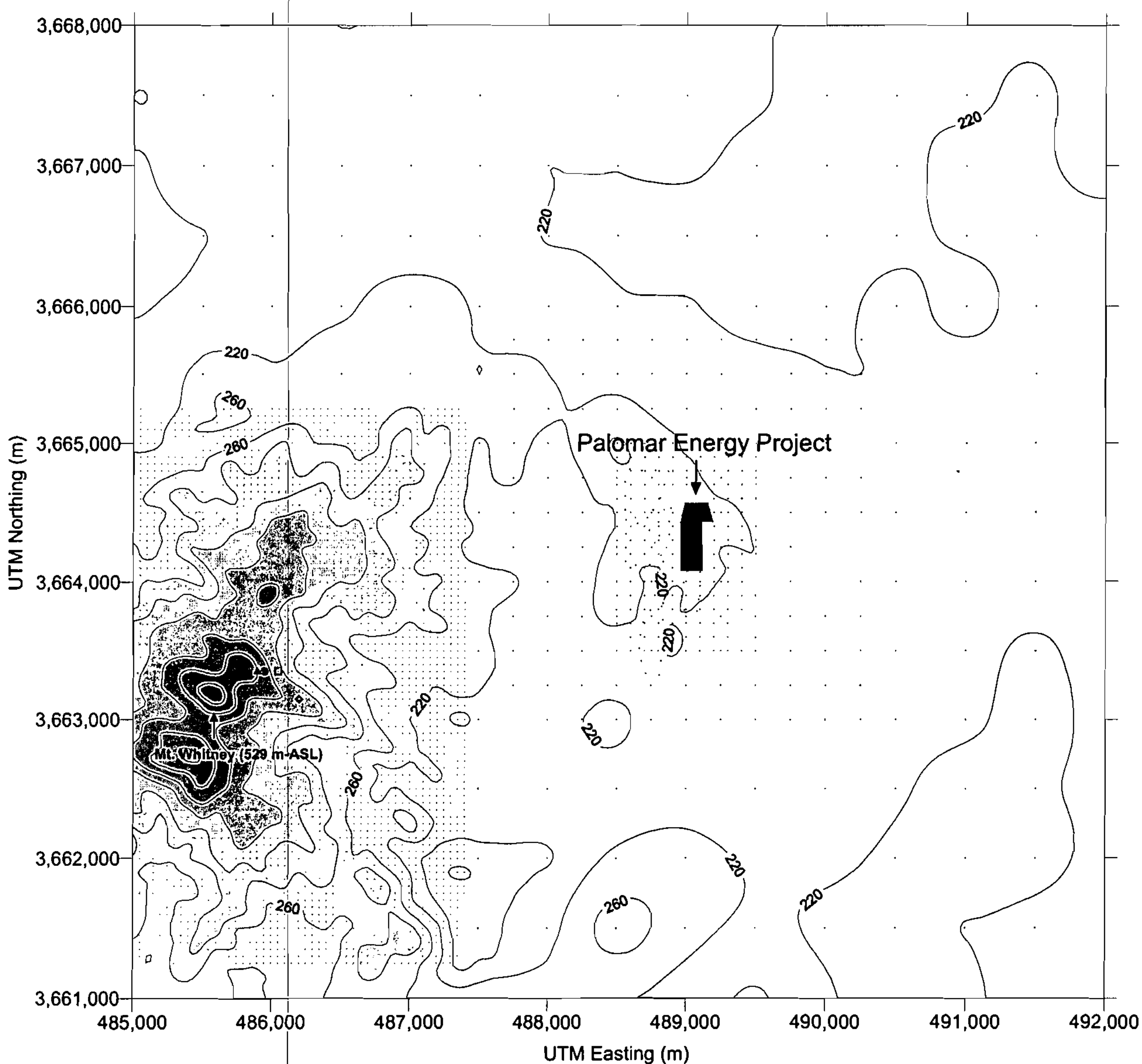
Modeled Concentrations and SILs Shown in $\mu g/m^3$

Terrain Elevations Shown in Meters Above Sea Level



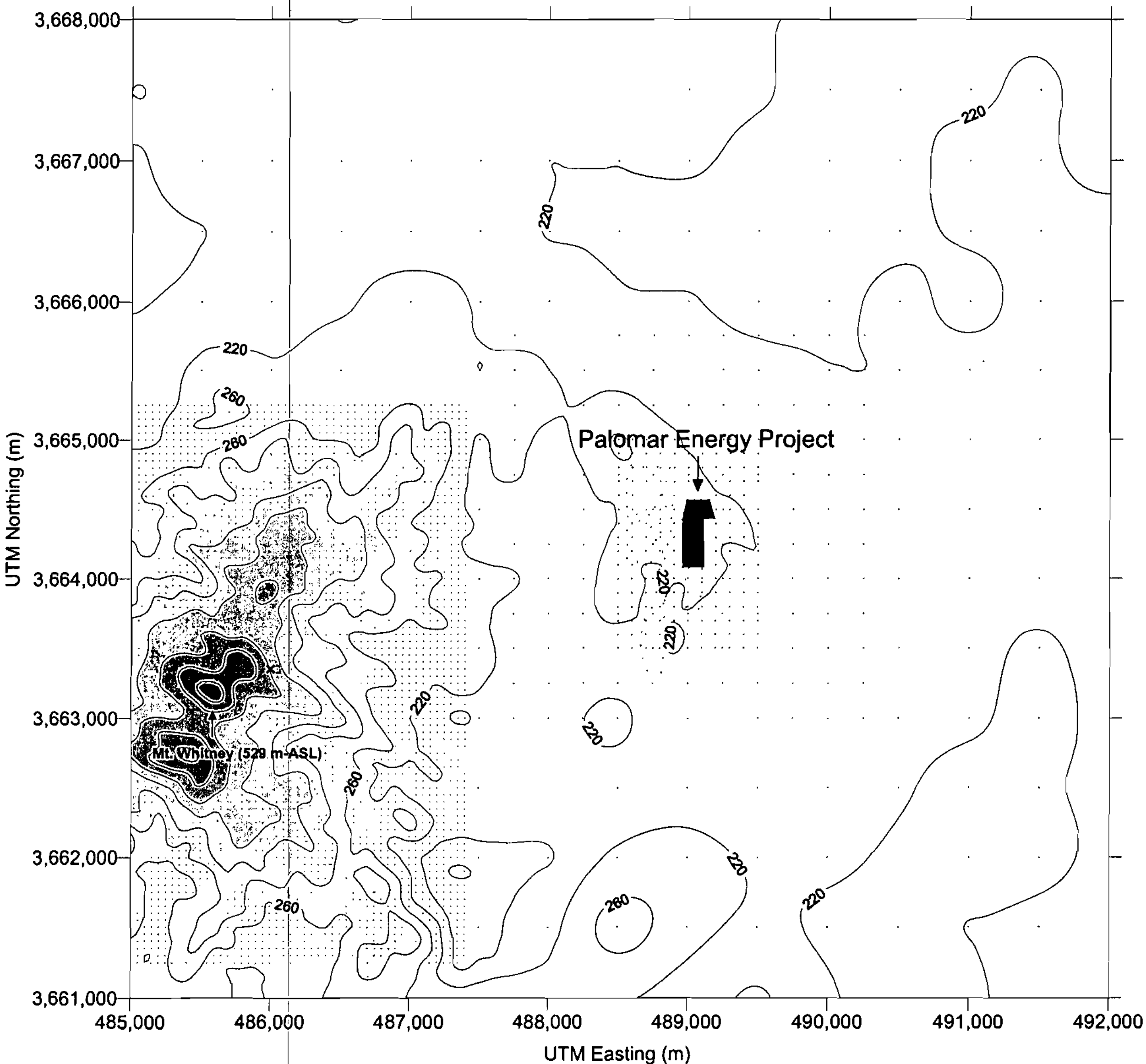
◇ = 1-hr NO2 (Project Impact = 24.8, No Applicable Significant Impact Level)
△ = Annual NO2 (Project Impact = 0.7, Significant Impact Level = 1)

Figure 5-2
Palomar Energy Project: DOC Application No. 976846
Maximum Modeled NO_2 Impact Locations During Normal Operations (Table 5-5)
Modeled Concentrations and SILs Shown in $\mu g/m^3$
Terrain Elevations Shown in Meters Above Sea Level



◇ = 1-hr SO2 (Project Impact = 7.5, No Applicable Significant Impact Level)
□ = 3-hr SO2 (Project Impact = 5.4, Significant Impact Level = 25)
● = 24-hr SO2 (Project Impact = 1.4, Significant Impact Level = 5)
▵ = Annual SO2 (Project Impact = 0.2, Significant Impact Level = 1)

Figure 5-3
Palomar Energy Project: DOC Application No. 976846
Maximum Modeled SO_2 Impact Locations During Normal Operations (Table 5-5)
Modeled Concentrations and SILs Shown in $\mu g/m^3$
Terrain Elevations Shown in Meters Above Sea Level



□ = 24-hr PM10 (Project Impact = 4.8, Significant Impact Level = 5)

× = Annual PM10 (Project Impact = 0.8, Significant Impact Level = 1)

Figure 5-4
Palomar Energy Project: DOC Application No. 976846
Maximum Modeled PM_{10} Impact Locations During Normal Operations (Table 5-5)
Modeled Concentrations and SILs Shown in $\mu g/m^3$
Terrain Elevations Shown in Meters Above Sea Level

The results also demonstrate that facility operations would not cause or contribute to an exceedance of the PM_{10} Federal Ambient Air Quality Standard or the California Annual Ambient Air Quality Standard. Since the project area is designated non-attainment for the California 24-Hour Ambient Air Quality Standard additional modeling was performed in order to determine whether the facility would cause additional violations of that standard.

> It should be noted that predicted concentrations for PM_{10} did not exceed the EPA specified NSR 24-hour or Annual Significant Impact Levels. Predicted impacts less than SILs are normally considered to not significantly affect compliance with Federal Ambient Air Quality Standards regardless of the background level. Specifically in non-attainment areas, project impacts less than the SILs are deemed to not cause or contribute to violations of the Ambient Air Quality Standard.

Since the initial modeling estimated maximum PM_{10} impacts of approximately 5 μ/m^3 additional AERMOD modeling was performed for all days in the 1998-2000 that PM_{10} background concentrations were between 45 μ/m^3 and 50 $\mu g/m^3$ (California Standard) to determine whether additional violations would result from facility operations. The results are presented in Table 5-6 and demonstrate that facility operations would not cause additional violations of the California 24-hour Ambient Air Quality Standard for PM_{10}.

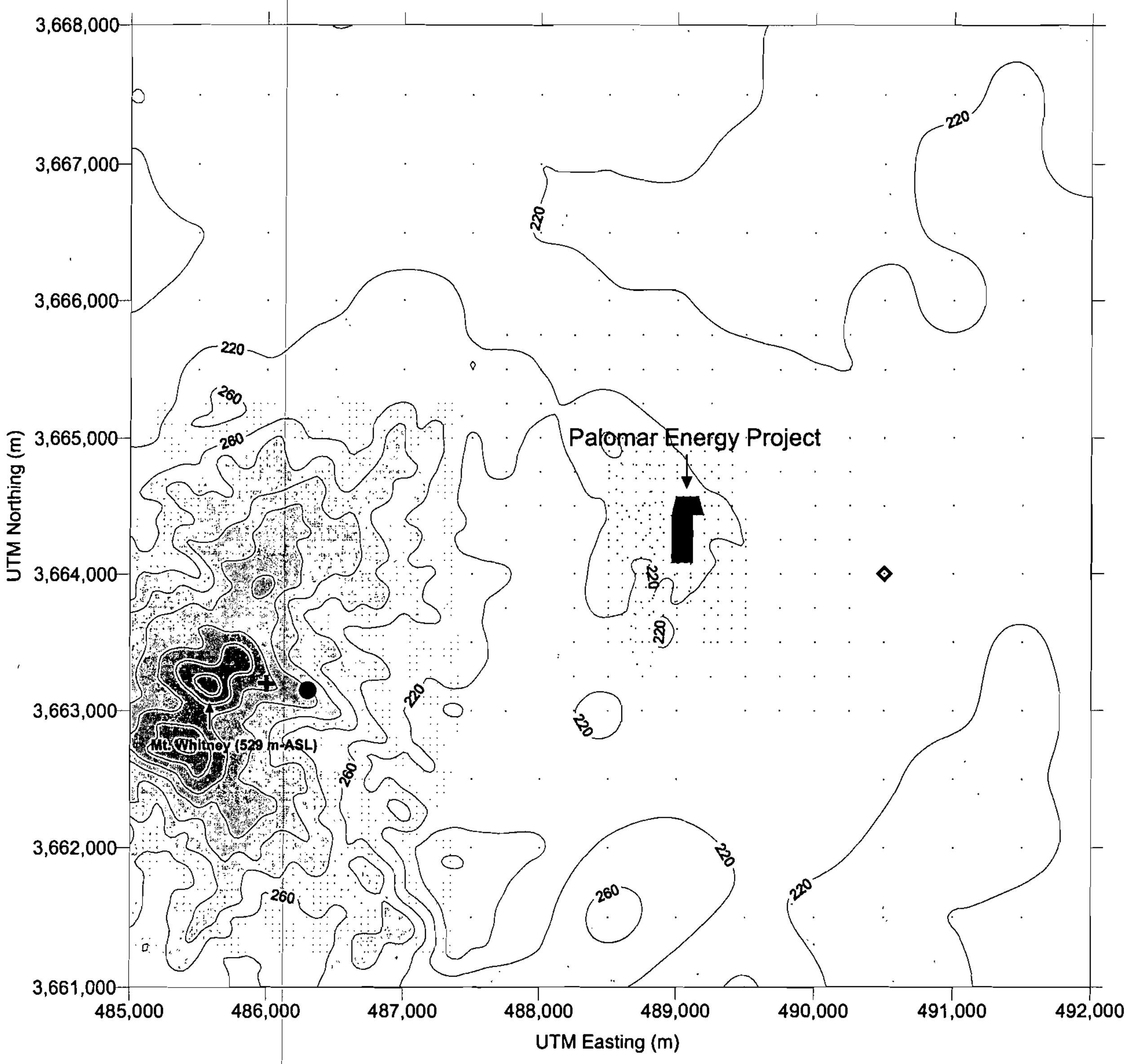
Table 5-6 Maximum Total PM_{10} Impacts During Normal Operations

Date	Background ($\mu g/m^3$)	Project Impact ($\mu g/m^3$)	Case [a]	Total Impact ($\mu g/m^3$)
3/1/99	48	0.08	12	48
5/12/99	47	0.23	1	47
11/2/99	47	0.05	1	47
11/14/99	50	0.03	1	50
12/20/99	48	0.13	12	48
11/20/00	49	0.003	4	49

[a] Case corresponds to the load and temperature combinations shown in Table C-1 of the DOC application.

5.2 PREDICTED AMBIENT AIR QUALITY IMPACT DURING COMMISSIONING

The modeling analysis for commissioning period conditions consisted of the maximum short-term NO_x and CO emissions rates. PM_{10} and SO_2 commissioning period emissions were not modeled since they are not significantly different than during normal operations. Table 5-7 presents the predicted ambient air quality impacts during commissioning. Table 5-8 provides information regarding the operating scenario (emission rate and release parameters) resulting in the predicted maximum impacts. Table 5-9 provides information regarding the location and Date/Time of the maximum impacts. Figure 5-5 presents the locations of the maximum predicted impacts during commissioning. The results demonstrate that facility commissioning period operations will not cause or contribute to an exceedance of the Federal and California



+ = 8-hr CO (Total Impact Including Background = 8392, Air Quality Standard = 10,000)
● = 1-hr CO (Total Impact Including Background = 17,819, Air Quality Standard = 23,000)
◇ = 1-hr NO2 (Total Impact Including Background = 270.4, Air Quality Standard = 470)

Figure 5-5
Palomar Energy Project: DOC Application No. 976846
Maximum Modeled Impact Locations During Commissioning (Table 5-7)
Modeled Concentrations and Air Quality Standards Shown in $\mu g/m^3$
Terrain Elevations Shown in Meters Above Sea Level

Ambient Air Quality Standards for NO_2, or CO. The results indicate that the CO 1-Hour and 8-Hour Class II area SILs may be exceeded during the commissioning period however since PSD increments have not been enacted for CO in the Federal Clean Air Act and the AAQS analysis indicates no violations of California and/or Federal standards no further analysis is required.

Table 5-7 Estimated Ambient Air Quality Impacts During Commissioning

Pollutant	Averaging Period	Maximum Modeled Impact (μg/m³)	Background [a] (μg/m³)	Total Predicted Concentration [b] (μg/m³)	Ambient Air Quality Standard [c]
NO_2	1-hour	240 [d]	30 [e]	270	470
CO	1-hour	5949	11,870	17819	23,000
	8-hour	2269	6,123	8392	10,000

[a] Background air quality data for NO_2 and CO obtained from the Escondido monitoring station during the period 1998-2000.
[b] All total impacts rounded to three or fewer significant figures.
[c] Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.
[d] NO_2 impact determined using Ozone Limiting Method.
[e] 1-hour NO_2 measured at the Escondido monitoring station during maximum ozone limited NO_2 impact Date/Time.

Table 5-8 Modeling Parameters Used for Commissioning Modeling [a]

Pollutant	Averaging Period	Stack Temp (K) [b]	Exit Velocity (m/s) [c]	Emission Rate (lb/hr/ turbine)	Operating Scenario
NO_2	1-hour	346.5	15.3 (Case 1) 14.9 (Case 5) 14.7 (Case 9)	450	All 50% loads (cases 1, 5, and 9) had the same impact: 50% load without duct firing at 20, 60, and 110-deg F ambient T
CO	1-hour	349.3	12.6	2000	20% load conditions
	8-hour	349.3	12.6	2000	20% load conditions

[a] Stack parameters and emissions reflect the revised commissioning modeling submitted with AFC Data Response #6
[b] Stack temperatures for NO_2 and CO modeling were obtained from the Colusa Power Plant Project (01-AFC-10) for each pollutant.
[c] Exit velocity for NO_2 modeling from Palomar 50% load cases. Exit velocity for CO was estimated using the Colusa Power Plant Project 20% load condition for an identical turbine.

Table 5-9 Commissioning Period Impact Location, Date/Time [a]

Pollutant	Averaging Period	UTM Easting (m)	UTM Northing (m)	Project Impact (mg/m^3)	Date/Time (yymmddhh)	Model	Turbine Case
NO_2 [b]	1-hour	490,500	3,664,000	240	98083012	ISCST3	1,5,9
CO	1-hour	486,300	3,663,150	5949	99092203	AERMOD	20% [c]
	8-hour	486,000	3,663,200	2269	98101808	AERMOD	20% [c]

[a] Impacts reflect the revised commissioning modeling submitted with AFC Data Response #6
[b] NO_2 impacts determined using Ozone Limiting Method
[c] Stack parameters for CO modeling were updated in AFC Data Response #6

5.3 PREDICTED AMBIENT AIR QUALITY IMPACT DURING STARTUP CONDITIONS

The modeling analysis for startup conditions consisted of the maximum short-term NO_x and CO emissions rates. PM_{10} and SO_2 startup emissions were not modeled since they are not significantly different than during normal operations. Table 5-10 presents the predicted ambient air quality impacts during startup. Table 5-11 provides information regarding the operating scenario (emission rate and release parameters) resulting in the predicted maximum impacts. Table 5-12 provides information regarding the location and Date/Time of the maximum impacts. Figure 5-6 presents locations of predicted maximum impacts during Startups. The results demonstrate that facility Startup operations will not cause or contribute to an exceedance of the Federal and State Ambient Air Quality Standards for NO_2 or CO. The results indicate that the CO 1-Hour and 8-Hour Class II area SILs may be exceeded during startups however since PSD increments have not been enacted for CO in the Federal Clean Air Act and the AAQS analysis indicates no violations of California and/or Federal standards no further analysis is required.

Table 5-10 Estimated Ambient Air Quality Impacts During Startup

Pollutant	Averaging Period	Maximum Modeled Impact ($\mu g/m^3$)	Background [a] ($\mu g/m^3$)	Total Predicted Concentration [b] ($\mu g/m^3$)	Ambient Air Quality Standard [c]
NO_2	1-hour	266 [d]	191 [e]	457	470
CO	1-hour	4500	11,870	16370	23,000
	8-hour	1397	6,123	7520	10,000

[a] Background air quality data for NO_2 and CO obtained from the Escondido monitoring station during the period 1998-2000.
[b] All total impacts rounded to three or fewer significant figures.
[c] Most stringent of federal or state ambient air quality standard for each pollutant and averaging period.
[d] Assumes 100 percent conversion of NO_x to NO_2.
[e] Maximum 1-hour NO_2 measured at the Escondido monitoring station.

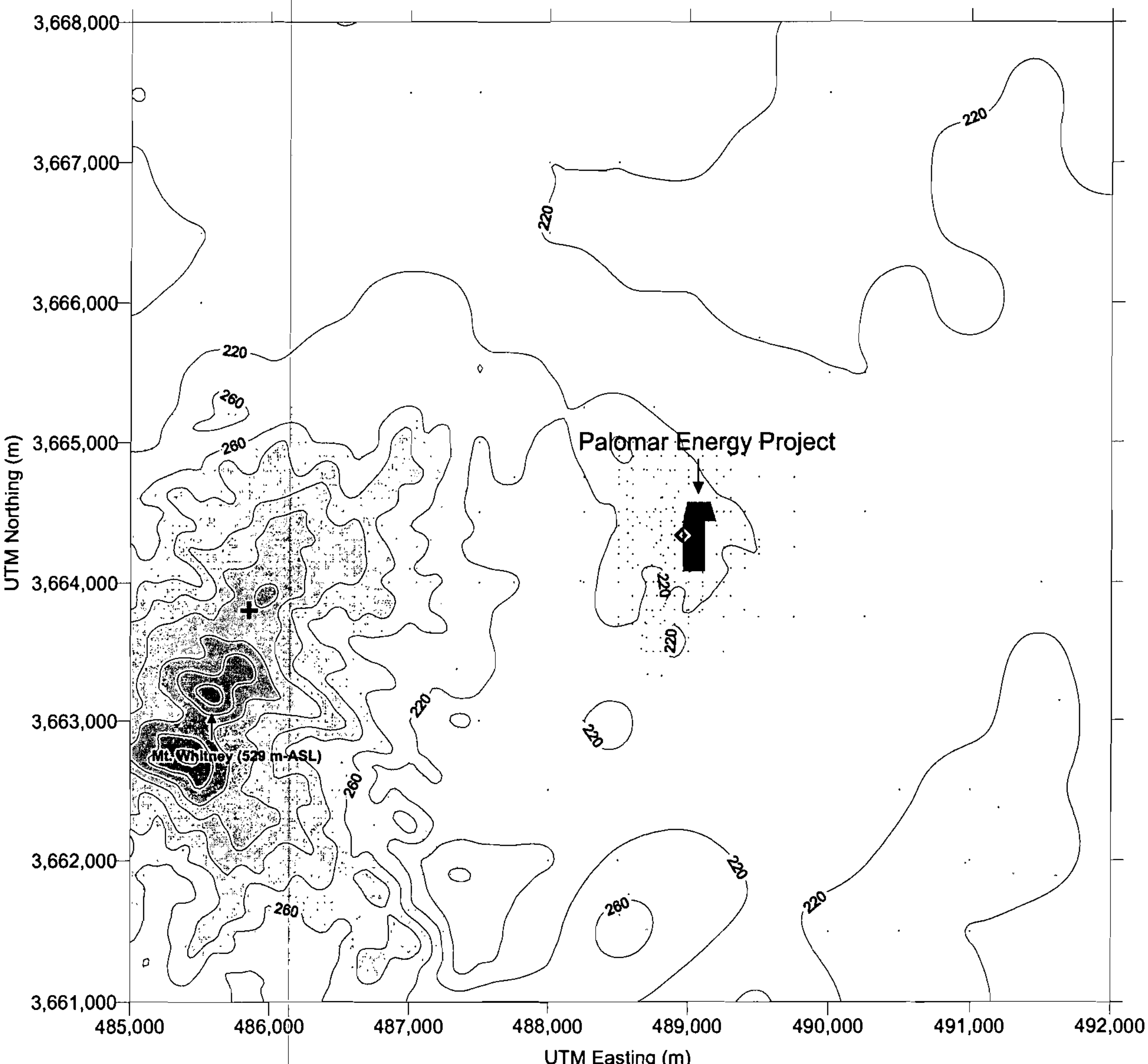
Table 5-11 Modeling Parameters Used for Startup Modeling [a]					
Pollutant	**Averaging Period**	**Stack Temp (K)**	**Exit Velocity (m/s)**	**Emission Rate (lb/hr/turbine)**	**Operating Scenario**
NO_2	1-hour	360.9	14.7	100	Case 9: 50% load without duct firing, 110-deg F ambient T
CO [b]	1-hour	360.9	14.7	1692	Case 9: 50% load without duct firing, 110-deg F ambient T
	8-hour	360.9	14.7	1692	Case 9: 50% load without duct firing, 110-deg F ambient T

[a] Stack parameters for 50% load conditions were used to represent release parameters during start-up. The three 50% load cases were modeled (i.e., cases 1, 5 and 9); the worst case impacts are presented in this table.
[b] Impacts for CO were proportionally increased to reflect higher CO emissions (see AFC Data Response #7). The modeled emission rate in DOC Application was 470 lb/hr/turbine. The resulting scaled emission rate for CO during startup is therefore 1692 lb/hr/turbine.

Table 5-12 Startup Conditions Impact Location, Date/Time

Pollutant	Averaging Period	UTM Easting (m)	UTM Northing (m)	Project Impact (mg/m^3)	Date/Time (yymmddhh)	Model	Turbine Case [c]
NO_2 [a]	1-hour	488,958	3,664,332	266.0	98112921	ISCST3	9
CO [b]	1-hour	488,958	3,664,332	4500	98112921	ISCST3	9
	8-hour	485,850	3,663,800	1397	00112108	AERMOD	9

[a] Assumes 100% conversion of NO_x to NO_2
[b] Impacts for CO were proportionally increased to reflect higher CO emissions (see AFC Data Response #7). Since only the emission rate changed, the location and date/time from the modeling submitted with the DOC application have not changed.
[c] Stack parameters for 50% load conditions were used to represent release parameters during start-up. The three 50 % load cases were modeled (i.e., cases 1, 5 and 9); the worst case impacts are presented in this table.



+ = 8-hr CO (Total Impact Including Background = 7520, Air Quality Standard = 10,000)

◇ = 1-hr CO (Total Impact Including Background = 16,370, Air Quality Standard = 23,000)

◇ = 1-hr NO2 (Total Impact Including Background = 457, Air Quality Standard = 470)

Figure 5-6
Palomar Energy Project: DOC Application No. 976846
Maximum Modeled Impact Locations During Start Up (Table 5-10)
Modeled Concentrations and Air Quality Standards Shown in μg/m^3
Terrain Elevations Shown in Meters Above Sea Level

6.0 PSD CLASS I ANALYSIS

An analysis of the potential project impacts with respect to the PSD Class I increments was performed. There are two Class I areas (Agua Tibia and San Jacinto Wilderness Areas) within 62 miles (100 km) of the Palomar site. The locations of these areas with respect to the project are shown in Figure 6-1.

The AERMOD modeling was used to conduct the PSD Class I air quality analysis at Agua Tibia Wilderness Area (within 50 km) since all receptor elevations are above stack height. The CALPUFF model was used to conduct the PSD Class I air quality analysis at the San Jacinto Wilderness Area which is greater than 50 km from the project location.

PSD regulations require that the project's potential impact on Air Quality Related Values (AQRVs) for Class I areas as determined by the Federal Land Manager (FLM) also be evaluated. For this project since both potentially impacted Class I areas are Wilderness Areas the FLM is the U.S. Forest Service. The applicable AQRV guidelines reflect the latest FLAG (2000) report and include impacts on visibility/regional haze and acid deposition. As discussed in Section 4 above, the VISCREEN, PLUVUE II, and CALPUFF models were used for these analyses.

6.1 COMPLIANCE WITH PSD INCREMENTS

The Project's predicted impacts will not exceed proposed Class I significant impact levels for SO_2, PM_{10} and NO_2. Results of the increment analysis for both Class I areas are provided in Table 6-1. The results demonstrate that the facility operation will not result in an exceedance of any PSD increment in a Class I area.

Table 6-1 Class I PSD Increment Results

Pollutant	Averaging Period	Agua Tibia Maximum Modeled Impact (μg/m^3)	San Jacinto Maximum Modeled Impact (μg/m^3)	Proposed Class I Area Significant Impact Levels[a] (μg/m^3)	Class I Area Increment (μg/m^3)
SO_2	Annual	0.002	0.005	0.1	20
	24-hour	0.027	0.040	0.2	91
	3-hour	0.170	0.138	1.0	512
PM_{10}	Annual	0.005	0.018	0.2	17
	24-hour	0.091	0.139	0.3	30
NO_2	Annual	0.006	0.008	0.1	25

a. Source: EPA proposed New Source Review reform, FR 7/23/96.

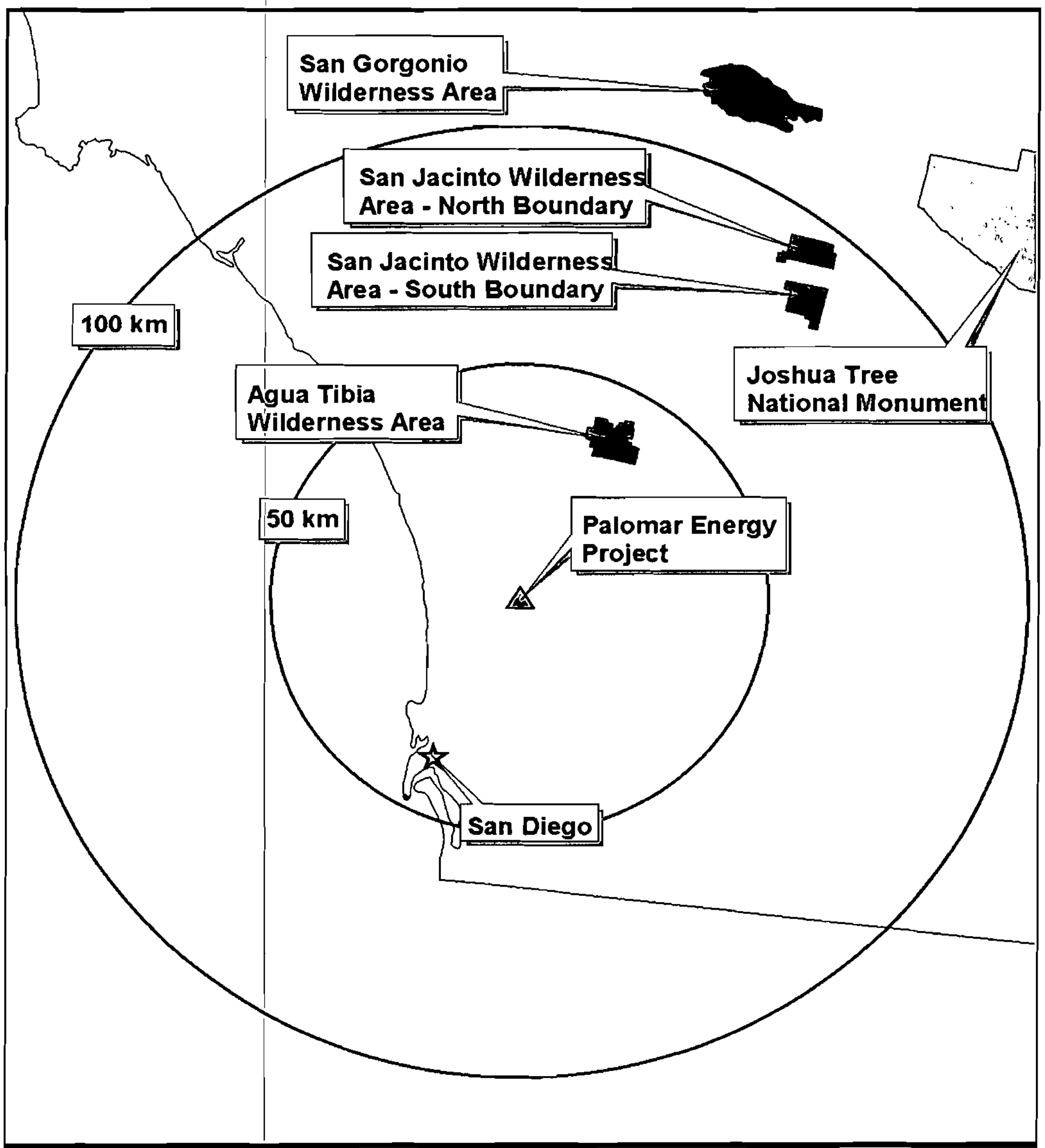


Figure 6-1 Project and Class I Area Locations

6.2 AIR QUALITY RELATED VALUE (AQRV) IMPACTS-VISIBILITY

PSD regulations require an assessment of visibility impairment attributable to the project in Class I areas within 100 kilometers of the project location. There are two types of visibility degradation that must be evaluated; plume blight and regional haze. Plume blight is caused when an observer is able to see a visible plume that reduces visual range when the observer looks along or through the plume. A plume blight analysis is required for Class I areas within 50 kilometers of the project, in this case the Agua Tibia National Wilderness Area.

The first two levels for screening visibility impacts using VISCREEN at Agua Tibia Wilderness showed potential exceedances of the screening criteria for plume perceptibility and contrast. Therefore, a Level-3 plume visibility analysis was performed using the PLUVUE II model, which is recommended by EPA (1992). A detailed discussion regarding the meteorological conditions, plume observer distances, and background values is provided in the modeling protocol in Appendix D of the Application for Determination Of Compliance.

The results of the analysis are provided in Table 6-6 of the DOC and indicate that all modeled values of plume perceptibility (ΔE) and contrast (C_p) are well below the screening thresholds of 2.0 and +/- 0.05, respectively (EPA, 1992). For a sky background, the highest magnitude plume contrast is -0.007 and the largest ΔE is 0.236. For terrain, the highest values simulated for a black background are 0.852 for ΔE and 0.025 for C_p. For a more realistic gray terrain background the maximum values are 0.017 for C_p and 0.618 for ΔE.

6.3 AIR QUALITY RELATED VALUE (AQRV) IMPACTS-REGIONAL HAZE

A regional haze analysis is required for all Class I areas more than 50 km but less than 100 km of the project location. Regional Haze is caused by the uniform particulate loading of the atmosphere that contributes to the attenuation of light. Beyond 50 km it is assumed that individual plumes have lost their coherence and the pollutants from the plume, including secondary aerosol, contribute to the general background loading of fine particulate matter. The CALPUFF model was used for this analysis. Regionally representative meteorological data as described in Section 4.2 above was used. The results of the regional haze analysis are summarized in Table 6-2. As shown in the table, the maximum extinction change from the background never exceeds five percent. A five percent change in extinction coefficient is generally considered the lowest perceptible change, and is used as a significance threshold for visibility impacts. Thus, the Palomar Energy project will not have an adverse regional haze impact.

Table 6-2 Maximum 24-Hour Average Regional Haze Impacts on San Jacinto Wilderness Area

Model Year	Maximum Extinction Change from Background (%)	Number of Days Maximum Change from Background is > 5%
1986	2.61	0
1987	2.21	0
1988	3.02	0
1989	3.19	0
1990	2.77	0

6.4 AIR QUALITY RELATED VALUE (AQRV) IMPACTS-ACID DEPOSITION

Based on information presented on the USFS website both Agua Tibia and San Jacinto Wilderness Areas have an AQRV associated with aquatic resources. NO_x and SO_2 emissions can affect aquatic resources through nitrogen and sulfur deposition.

The CALPUFF model is generally used to determine the potential for impacts from acid deposition in Class I areas. CALPUFF screening modeling provided upper limit estimates of annual (wet and dry) deposition of sulfur and nitrogen compounds (computed as kilograms per hectare per year (kg/ha/yr)) associated with Palomar Energy Project emissions of SO_2 and NO_x. Table 6-3 summarizes the maximum modeled annual sulfur and nitrogen deposition for the Agua Tibia and San Jacinto Wilderness Areas.

Table 6-3 Annual Deposition of Sulfur and Nitrogen at Agua Tibia and San Jacinto Wilderness Areas

Class I Area	Species	Annual Deposition (kg/ha/yr)
Agua Tibia	Sulfur	0.0013
	Nitrogen	0.0014
San Jacinto	Sulfur	0.0012
	Nitrogen	0.0013

No regulatory thresholds for acid deposition have been established for the Class I Areas. Modeled acid deposition impacts are more than two orders of magnitude below the minimum detectable limit for wet deposition (0.5 kg/ha/yr), and more than an order of magnitude below the conservative USFS significance threshold of 0.05 kg/ha/yr. Values for nitrogen are below the Deposition Analysis Threshold (DAT) of 0.005 kg/ha/yr being developed for Western Class I areas (FLAG, 2001). A DAT for sulfur has not yet been developed. Since increased nitrogen and sulfur deposition due to the proposed project will be insignificant, impacts to stream and river Acid Neutralization Capacity (ANC) and pH, and therefore acidification and/or eutrophication are not likely to occur.

6.5 AIR QUALITY RELATED VALUE (AQRV) IMPACTS-VEGETATION

The USFS has developed information defining vegetative ecosystems and sensitive vegetative species for Class I areas. Sensitive species of trees, plants and lichens are primarily impacted by ozone however they may also be impacted by nitrogen and sulfur compounds. Based upon the maximum predicted pollutant concentrations for the Palomar Energy project in both Class I areas potential vegetation impacts are expected to be insignificant. A discussion of the Class I area vegetation analysis performed is contained in Section 6.5.2 of the DOC.

7.0 OTHER RELATED ANALYSES

EPA, PSD and SDAPCD regulations require that additional analyses be performed for major stationary sources. The additional analyses required for the Palomar Energy Project include Vegetation and Soils impacts, Area Growth Analysis and an Alternatives Analysis. Section 6.6 of the DOC provides the required analyses for the project. The analyses provided indicate no or an insignificant impact for Vegetation and Soils, no project associated growth issue and satisfies the requirements of Rule 20.3(e) (2).

8.0 CONCLUSIONS

From the review of the submitted modeling and associated results contained in the Application for DOC dated November 27, 2001, operation of the proposed Palomar Energy Generating facility will be in compliance with all New Source Review (NSR) and Prevention of Significant Deterioration (PSD) requirements with regard to impact thresholds and additional project impact analysis requirements for all Class I and II areas.

MEMO

May 9, 2002

To: Evariste Haury, via Tom Weeks

From: Dick Brightman

Health Risk Assessment Review
Palomar Energy Project

The District has reviewed the Health Risk Assessment (HRA) prepared by ENSR for the Palomar Energy, LLC natural gas-fired power plant. Palomar Energy, LLC is a subsidiary of Sempra Energy Resources. The project is two GE 7FA gas-fired turbines each rated at 1722 million BTU/hr (HHV) with duct burners, selective catalytic reduction, oxidation catalyst system, and seven cooling towers. The project is located 600 feet southwest of the intersection of Vineyard Avenue and Enterprise Street in Escondido, California.

The District's conclusion is that the health risk assessment was conducted according to State and District Guidelines and that the estimated health risks from the project are less than the District regulatory limits of 1 per million cancer risk and acute and chronic health hazard indices less than 1 at all likely offsite receptors. Specific comments are as follows.

1. Emission calculations for the turbines used in the HRA were based on California Air Toxics Emissions Factors (CATEF) which are generally consistent with District emissions factors for gas-fired turbines. The primary VOC toxicant of concern for cancer effects is formaldehyde, and the primary VOC toxicant of concern for acute health effects is acrolein. In both cases, the CATEF emission factor is higher than the District default emission factor. There is also information in the EPA database on which the District default emission factor for formaldehyde is based suggesting that formaldehyde emissions from the type of turbine being proposed may be substantially less than either of the above factors. Consequently, the CATEF emission factors used in the HRA are conservative, and are acceptable to the District. In the case of poly-aromatic hydrocarbon emissions (PAHs), the CATEF factors are speciated for specific TAC PAHs whereas the District default is not. For this HRA, the emission factors for all non-regulatory PAHs (those non-regulatory PAHs for which data is insufficient for OEHHA to determine a cancer unit value) were summed. Most of the PAH emissions for this project are of non-regulatory PAHs, and are comparable to emissions estimated from the District default emission factor, corrected for naphthalene. The HRA nevertheless conservatively assumed all non-regulatory PAHs to have the same unit risk as Benzo(a)Pyrene. The same conservative approach has been used for other recent applications of this type and is acceptable to the District.

2. Emission calculations for the cooling towers were based on City of Escondido data on maximum concentration of metal TACs from sampling of reclaimed water used in the cooling towers, maximum total dissolved solids levels, maximum cooling water re-circulation rates, and a drift fraction of 0.0005 %. No information has been received by the District suggesting the presence of other TACs, and the emissions calculations are acceptable to the District.

3. The HRA concludes that the maximum lifetime cancer risk from the project is 0.92 in a million at a location in the elevated terrain of the Coronado Hills approximately 3 kilometers west of the proposed plant. This was based on refined air dispersion modeling using ISC3 for lower elevations and AERMOD for elevated terrain. Since the peak risk occurs in elevated terrain, the AERMOD results are of primary concern. AERMOD calculations were done using meteorology data based on District measurements of wind speed and direction for the Escondido area together with upper air data from Miramar Air Station. The Modeling and Meteorology Section has determined that the AERMOD modeling used in this HRA provides acceptable estimates of air dispersion for this project.

4. Based on an assumed maximum natural gas consumption rate of 1.92 MMscf per hour per turbine, an average natural gas consumption rate of 1.81 MMscf per hour per turbine combined with 8760 annual hours of operation, an assumed TAC control efficiency of 50 %, the CATEF emission factors and cooling water emission data, and multi-pathway factors based on the ACE2588 calculations performed for this HRA, source strengths for the turbines and cooling towers were calculated by the District and combined with maximum annual dispersion factors from the AERMOD calculations for the highest impact year (2000). The resulting total lifetime cancer risk was calculated by the District to be 0.95 in a million, in agreement with the HRA.

5. Using the same throughput and emissions data, the District performed calculations using ISC3 to verify that expected chronic and acute health hazard indices would be less than 1. The ISC3 modeling is expected to be more conservative than the AERMOD calculations performed for the HRA. The maximum chronic health hazard index was found to be 0.21, and the maximum acute health hazard index was found to be 0.31, both less than the regulatory level of concern.

6. The HRA combined ISC3 and AERMOD air dispersion modeling with multipathway risk calculations using the ACE2588 model. Review of the calculations showed that 55% of the maximum lifetime cancer risk was due to the non-regulatory PAHs that have no OEHHA unit risk factors, but were conservatively assumed to be as toxic as benzo(a)pyrene. Of this portion of the total risk, 76% was due to the plant pathway. This was a result of assuming that the maximally exposed receptor derived 15% of their ingestion of garden vegetables from a home garden, which may be conservative for the suburban neighborhood of the maximally exposed receptor.

7. Under startup conditions, the worst case would be to assume the same maximum natural gas consumption rate of 1.92 MMscf per hour per turbine, no controls, and the same release parameters. Based on conservative ISC3 modeling. The District estimates that the maximum acute health hazard index should not exceed 0.62 which is still under the regulatory level.

8. Review of the pathway data file used for the HRA showed that it was concordant with the 1993 CAPCOA guidelines. Review of the pollutant-specific toxicity file used for the HRA showed the following discrepancies with the latest OEHHA values:

A cancer potency for PAH of 11.5 $(mg/kg\text{-}d)^{-1}$ was used in place of the current 12 $(mg/kg\text{-}d)^{-1}$. Correcting the HRA for this discrepancy results in a revised District estimate of the maximum cancer risk of 0.97 in a million.

A chronic REL for 1,3-butadiene of 0 $\mu g/m^3$ was used in place of the current 20 $\mu g/m^3$. A chronic REL for ethylbenzene of 2.3E+03 $\mu g/m^3$ was used in place of the current 2.0E+03 $\mu g/m^3$. The effect of correcting the HRA for these discrepancies is to leave the chronic HHI unchanged because the relative contributions of these chemicals to the total HHI is about 10,000 times less than the risk drivers, which are acrolein, formaldehyde, and ammonia.

An oral dose for Cadmium of 1.0E-03 mg/kg-d was used in place of the current 5.0E-04 mg/kg-d. The effect of correcting the HRA for this discrepancy would be to decrease the chronic HHI. Since cadmium contributes about 10,000 times less to the chronic HHI than the chronic risk drivers, acrolein, formaldehyde, and ammonia, this decrease would be very small.

All cancer unit risk values used in the HRA were concordant with the latest OEHHA values.

cc: Mike Lake
Dan Speer
Steve Moore
Ralph DeSiena

MEMO

November 27, 2002

To: Evariste Haury, via Tom Weeks

From: Dick Brightman

Supplemental Health Risk Assessment Review
Palomar Energy Project Cooling Towers

The District has reviewed the Supplemental Health Risk Assessment (HRA), dated November 2002 and prepared by ENSR for the Palomar Energy, LLC natural gas-fired power plant cooling towers. Palomar Energy, LLC is a subsidiary of Sempra Energy Resources. The project is two GE 7FA gas-fired turbines each rated at 1722 million BTU/hr (HHV) with duct burners, selective catalytic reduction, oxidation catalyst system, and seven cooling towers using reclaimed water from the Hale Avenue Resource Recovery Facility (HARRF). The project is located 600 feet southwest of the intersection of Vineyard Avenue and Enterprise Street in Escondido, California.

The supplemental health risk assessment was conducted in response to District efforts to ensure that all toxic air contaminants (TACs) that could reasonably be expected to be emitted from the cooling tower water were evaluated. The original risk assessment included only metals in the treated water from the Hale Avenue facility in Escondido. A number of additional volatile and non-volatile TACs were identified for which there was HARRF effluent data or for which emissions would be expected and which also had emission factors. These additional chemicals were included in the supplemental risk assessment. In addition, a number of TACs of concern were excluded from consideration, and justification for this was provided. The District has evaluated these justifications and considers them to be appropriate.

The District's conclusion is that the supplemental health risk assessment for the cooling towers is consistent with State and District Guidelines and that the estimated health risks from the cooling towers, when added to those for the turbines, are less than the District risk management criteria of 1 per million cancer risk and acute and chronic health hazard indices less than 1 at all likely offsite receptors. Specific comments are as follows.

1. Emission calculations for the cooling towers were based on City of Escondido quarterly effluent water quality analysis from the Hale Ave. facility for 1995-2002. Emission rates were calculated using this data and water re-circulation or makeup rates. Emissions for TACs without effluent data were calculated using SDAPCD emissions factors. The emissions appear to be correctly calculated. Emission calculations also include emission reductions resulting from tertiary treatment where appropriate.

2. The HRA concludes that the maximum lifetime cancer risk for the cooling towers is 0.0109 in a million at a location in the elevated terrain of the Coronado Hills approximately 3 kilometers west of the proposed plant. This was based on refined air dispersion modeling using ISC3 for lower elevations and AERMOD for elevated terrain. Since the peak risk occurs in elevated terrain, the AERMOD results are of primary concern. AERMOD calculations were done using meteorology data based on District measurements of wind speed and direction for the Escondido area together with upper air data from Miramar Air Station. The Modeling and Meteorology Section has determined that the AERMOD modeling used in this HRA provides acceptable estimates of air dispersion for this project.

3. Using the results of the dispersion modeling and the same emissions data, the District independently calculated the maximum cancer risk from the cooling towers to be 0.0104, which is considered to be good agreement. Since the District has previously verified the risk for the turbines to be no more than 0.94 in a million, the total cancer risk from the project should be no more than 0.95 in a million.

4. The District also verified the calculations of non-cancer chronic and acute health hazard index for the cooling tower. The maximum chronic health hazard index (HHI) for the cooling towers was estimated by the District to be 0.0022. Since the total project chronic HHI was originally calculated to be 0.21, the contribution from the cooling towers is negligible. The maximum acute health hazard index (HHI) for the cooling towers was estimated by the District to be 0.00019. Since the total project acute HHI was originally calculated to be 0.31, the contribution from the cooling towers is negligible, and both are less than the regulatory level of concern.

5. Review of the health risk assessment showed that the latest OEHHA-approved health values were used with the exception that chronic RELs for ammonia, sodium hydroxide, methyl ethyl ketone, fluoride, lindane, antimony, and copper have been withdrawn by OEHHA as of July 2002 and are no longer appropriate to use in HRAs. This means that the chronic HHI for the cooling towers is less than was calculated in the HRA. Since the chronic impact from the project is well below the level of concern, this has negligible impact.

6. The health risk assessment also included a re-analysis of the risk from the turbines. The District had previously approved the risk assessment for the turbines. The District has not yet reviewed the revised turbine HRA. The results of the turbine HRA will be revised if necessary based on that review.

cc: Mike Lake
Dan Speer

RESPONSE TO PUBLIC COMMENTS ON THE PRELIMINARY DETERMINATION OF COMPLIANCE (PDOC) FOR THE PALOMAR ENERGY PROJECT
APPLICATION NO.976846
December 6, 2002

California Energy Commission (CEC) COMMENTS:

1. Incomplete Emissions Reduction Credits (ERCs): The offsets package remains incomplete and is only generically identified in the PDOC (PDOC p. 34-35). Without clearly identified offset package, the California Energy Commission and the public cannot determine if the project will indeed comply with applicable laws, ordinance, regulations, and standards (LORS). Without having the offsets fully identified in a public document, the public has no way to understand which emission reductions will apply to the project. Furthermore, The PDOC does not present a clear path for Palomar Energy to obtain the remaining offsets. Given the competitive market in San Diego County, the District should address whether the applicant can secure sufficient ERCs to meet the project's schedule and offsets requirements.

   Additionally, by postponing the identification of the ERCs, any Environmental Protection (EPA) recommendations on the ERCs may arrive late in our process. Because the applicant and the Energy Commission staff depend on the ERC package for LORS compliance and project mitigation, the Energy Commission staff will not be able to recommend licensing the project without additional evidence that offsets will be provided.

   The District should certify whether complete offsets have been identified by noting the ERC certification number and owner, quantification, emission reduction source, and method of reduction.

   The quantity of ERCs required (148.8 tons, PDOC p.34 and condition 49) does not agree with the liability (124.4 tons) times the 1.2 offset ratio. The ERC requirement should be 149.3 tons.

   District Response: *The offset package was generically described in the PDOC because Palomar Energy was in negotiation with various companies at that time and had requested that part of the offset package description be kept confidential. Since issuance of the PDOC, additional ERCs have been purchased and the confidentiality of those ERCs is no longer necessary. Therefore, the District will identify all ERCs by identification number, quantification and owner.*

   As of December 6, 2002, Palomar Energy owns 87.5 tons of NOx equivalent credits and is in negotiation for an additional 38.5 tons. The District believes that *the applicant can secure sufficient ERCs to meet project's schedule and offset requirement.*

Because Palomar Energy reported 124.0 tons of NOx emissions in its application for the operation of the power plant, NOx emissions needed to be limited to that emission level which requires 148.8 tons of offsets. After issuance of the PDOC, the applicant has requested that NOx emissions be limited to 105 tons per year corresponding to the present available 126 tons of credit until sufficient emissions offsets are provided to cover the full potential to emit of 124.4 tons per year, which will require 149.3 tons of offsets. The District will make the changes accordingly in the FDOC.

2. BACT/LAER: According to the PDOC (p.51, Condition 31), the District is still evaluating the BACT/LAER determination for gas turbine NOx to determine if a limit of 2.0 ppm (1-hour average) without duct burners operating has been " demonstrated." On similar cases, the US EPA has commented that an emission limit of 2.0 ppm is achievable and demonstrated for NOx, CO, and VOC on a 1-hour average while simultaneously achieving 5 ppm ammonia slip. Energy Commission staff anticipates that U.S. EPA will make a similar comment on this BACT decision of the PDOC.

   As noted in the PDOC (p.19), guidance from CARB indicates that an ammonia slip of 5 ppm should be achievable. Energy Commission staff experience and vendor guarantees also show that ammonia slip of 10 ppm. Because under certain circumstances ammonia can be a precursor to ambient PM_{10}, staff recommends that the District require the lower limit.

   District Response: *After reviewing the first quarter and second quarter 2002 CEMS data of Massachusetts ANP Blackstone power plant and after consultations with the applicant, the District is recommending a NOx LAER level of 2.0 ppm, 1-hour average except during duct burner operations and during certain transient conditions when a 2.0 ppm, 3-hour average limit will apply.*

   The District's NSR and prohibitory rules apply only to direct emission of PM_{10}. These rules do not have a BACT provision for ammonia. Ammonia is regulated as a toxic air contaminant under District Rule 1200. The District has examined the toxic impacts of ammonia by means of health risk assessment and determined that ammonia emissions would not cause a violation of any Office of Environmental Health Hazard Assessment (OEHHA) recommended exposure limit. Therefore the District will retain the 10 ppmv limit at 15% oxygen for ammonia slip.

3. Mitigation Fee: In a Response to Energy Commission staff data requests submitted to Energy Commission staff on May 8, 2002, the applicant proposed to

provide funds in the amount of $ 787,500 to the SDAPCD to reduce regional emissions. Energy Commission staff is attempting to analyze the ability of these funds to provide quantifiable, timely, and permanent air emission mitigation and air quality benefits but has little specific information from the applicant and comment on what types of specific air quality benefits might be realized, what the magnitude of emission reductions might be, and when they would be expected to occur.

Because the mitigation fee is part of the applicant overall mitigation strategy for the Energy Commission siting process, further consultation between the District, the applicant, and Energy Commission staff will be necessary for us to fully analyze the mitigation strategy.

District Response: *Discussion is taking place now on this issue between the District and Energy Commission Staff, and between the District and the applicant.*

4. Compliance Certification: The District affirms that Sempra Energy Resources and Palomar Energy, LLC do not operate any major sources in the State of California and thus, are in compliance with all Clean Air Act requirements (PDOC P.35). The District should address how operations of the parent entity Sempra Energy, and Sempra affiliates such as Sempra Energy Solutions, have been handled.

   District Response: *The applicant has provided a certification stating that there are no major sources operated in California by Sempra Energy, the parent entity of Palomar LLC.*

5. Cooling Tower Exemption**:** The PDOC states (p.15) that emissions from the cooling tower would cause no significant impacts. This statement is not substantiated by an explanation of what criteria were used to determine the significance of cooling tower impacts. The District should substantiate this assumption by explaining that either the quantity of the cooling tower emissions is below an applicable regulatory threshold or the ambient air quality impacts were found to not contribute to existing violations of the state 24-hour standard for PM_{10}.

   The regulatory exemption for this source is not identified. For example, a clarification should identify if BACT is required for this source under Rule 20.3(d)(1).

   Additionally, staff continues to disagree with the applicant's proposal that only 50% of the cooling tower water dissolved solids (TDS) would qualify as PM_{10}. This fraction is based on a theoretical analysis with no source-tested substantiation. Considering the complex chemical nature of the solids in the drift (not just sodium chloride) and the potential for multiple (meaning literally thousands) of potential particle nucleate from drift droplets. Furthermore, large-particle salts would be expected to settle and deposit near the project site. Local deposition of cooling water salts could cause impacts to species in the project vicinity that are listed under the Endangered Species Act (PDOC p.39), which may require further analysis. Because there is no source testing requirement to confirm that the installed mist eliminator actually functions at the given emission rate, Energy Commission staff feels that it is reasonable to analyze the impacts of the project assuming that 100% of the emitted TDS becomes PM_{10} in the ambient air.

District Response: *For the Air Quality Impact Analysis, cooling tower PM_{10} emissions were included in the modeling to estimate maximum PM_{10} impacts for the entire facility. Twelve different modeling scenarios were employed with varying ranges of loads, duct firing on or off, and varying ambient temperature. PM_{10} emissions ranged from 11 to 14 lb/hr for each turbine depending on the modeling scenario, or a total of 22 to 28 lb/hr for the turbines. The cooling tower emissions were estimated to be 0.65 lb/hr using a 50% fraction of the total dissolved solids (TDS). This is, at maximum, less than 3% of the total PM_{10} emissions for the facility. Both AERMOD and ISC were used to determine the maximum estimated 24 HR PM_{10} impact anywhere in the vicinity of the facility, which was 4.8 $\mu g/m^3$. Since we are non-attainment for the state PM_{10} 24 hr standard, additional analysis was performed to determine whether or not additional violations would occur as a result of the proposed facility operation. For this additional analysis, six non-exceedance days with background concentrations between 45 and 50 $\mu g/m^3$ were identified at the Escondido monitoring station for the 3-year period modeled. The modeling for this additional analysis was conducted as described above. The maximum predicted 24 hr impact from all PM_{10} emissions from the project for any of the six days was 0.23 $\mu g/m^3$, which when added to the background concentrations for the six days, would not cause an additional exceedance of the state 24 hr standard. If the emission from the entire facility were doubled for this analysis (which would include a 100% of TDS as PM_{10} assumption), doubling the estimated impact to 0.46 $\mu g/m^3$ an additional violation of the state 24 HR standard would still not result (See Table 6.3 of the DOC application).*

BACT as stated in rule 20.3 (d)(1) does not apply to cooling towers. District Rule 11 exempts cooling towers from the District permit requirements. The provisions of Rule 20.3 only apply to equipment which is required to have a Permit. Therefore the cooling towers for the Palomar Energy Project are not required to be equipped with the Best Available Control Technology (BACT).

Concerning the applicant proposal that only 50% of the cooling tower water dissolved solids (TDS) would qualify as PM_{10}, the District, as mentioned above, also performed a modeling analysis assuming 100% of TDS was emitted as PM_{10}.

This analysis resulted in no violation of the state 24 hr standard. There is evidence to indicate a 50% assumption for PM_{10} is reasonable: not the least of which is acceptance of such on prior projects. Therefore the District will report the facility PM_{10} in the FDOC assuming 50% of the cooling tower water TDS is converted into PM_{10}.

6. Miscellaneous Comments on Conditions: The applicant should be made aware that installing additional air emission sources, as would be allowed under Condition 4, could trigger a requirement for an amendment through the Energy Commissions Siting Regulations.

   Conditions 24 and 27 appear to be redundant. It may not be possible for the applicant to comply with Condition 27 during commissioning.

   Condition 38 limits the fuel input to the duct burners, but there appears to be no requirement for monitoring duct burner fuel flow. Condition 12 should be revised to require the duct burners be equipped with fuel flow monitors.

   Condition 46 refers to compliance with toxic air contaminant emission levels that are not defined elsewhere.

   Condition 47 refers to requirement in Condition 39, which may be a typo; it probably should refer to Condition 43.

   District Response:

   Condition 4: The District agrees and has modified this condition to require CEC approval prior to installing additional air emissions sources.

   Condition 24: Condition 24 addresses Rule 20.3 (d)(2)(i) whereas condition 27 addresses Rule 69.3.1. Therefore the two conditions are not redundant.

   Condition 27: The condition provides for an option to petition the Hearing Board for a variance when the applicant cannot meet the limit required by Rule 69.3.1. Therefore no changes are necessary for this condition.

   Condition 38: The District agrees and has changed Condition 12 to include flow rate monitoring for duct burners.

   Condition 47: The District agrees and has changed the condition accordingly.

   Condition 46: The District agrees and has amended the condition as well as the DOC text accordingly.

PALOMAR ENERGY COMMENTS

7. The PDOC contains a VOC limit of 2 ppm for the combined-cycled based on the ARB's Guidance for Power Plant Siting and Best Available Control Technology (1999). As further detailed in Attachement A, the ARB's guidance only addresses emissions from gas turbines, and does not address emissions from fired Heat Recovery Steam Generator (HRSG), which is a type of natural gas boiler. When accounting for this additional source of emissions, Palomar believes that a permit limit of 3 ppm for the combine-cycle is justifiable.

   District Response: *By definition a combined-cycle turbine has a Heat Recovery Steam Generator. In determining BACT for VOC the ARB's Guidance for Power Plant Siting (1999) took this fact into consideration. Also similar plants in California are required to meet the 2.0 ppm (3-hour average). Therefore the District believes the VOC limit of 2.0 ppm should remain unchanged.*

8. Before the plant can be tuned and operated, it is necessary to clean out the equipment, including mill scale, protective coating, and debris introduced during construction, using steam. This cleaning activity is called "boilout" or " steam blows" and refers to purging foreign material from the inside of the steam paths and from outside of the tubes using steam when the turbines and HRSG first come on line. The steam for this activity is generated in the HRSG, and the turbine must run at low load for the equipment to function properly. Even though it involves firing fuel in the combustion turbine, boilout is considered to still be a construction activity. Attachment B contains a recent (December 2001) letter from EPA Region 9 that concurs with this conclusion for New Source Review purpose. Permit conditions related to operation of the equipment should not take effect until after completion of construction. Therefore, Please replace the term "initial firing" in the permit with " initial startup" (meaning after completion boilout) on page 41 and in conditions 9, 10, 12, 17, 18, 23, 25, 29 and 49.

   District Response: *Although EPA considers boilout of gas turbines as a construction activity rather than commencement of operation and, as such, should be considered as initial startup, this differs with District Rule 69.3.1 which implies the contrary. The District will accept the wording if there is no commercial sale of power to grid during the boilout period. The change will be made with specification that there is no commercial sale of power.*

9. The footnote and parenthetical phase regarding the PM_{10}/TDS assumption in the header of table 2b are confusing and unnecessary, and should be deleted. The statements on the proceeding page and the statement before the table regarding the basis is sufficient.

District Response: *The District agrees and has made the appropriate change.*

10. The maximum potential NOx and CO during the commissioning phase in Table 3 should be 35.3 tons and 47.6 tons, respectively, corresponding to Table 4-1 in the Palomar application. The maximum PM_{10} during commissioning phase in Table 3 should be 4.3 tons to account for operation of the cooling tower during the 300 hours.

District Response: *Commissioning period turbine emissions were changed by Palomar Energy to reflect the following numbers (450 lbs/hr per gas turbine for NOx and 2000 lbs per gas turbine for CO). These numbers were used for the modeling of the commissioning period and are therefore used, instead of the numbers listed in Table 4-1 in the Palomar application. The District disagrees with the maximum potential NOx and CO emissions calculated by the applicant and listed in Table 3 as (35.3 and 47.6 tons).*

The numbers in Table 3 of the PDOC are potential emissions for the gas turbines only and not the entire facility. Therefore PM_{10} emissions accordingly should not include cooling towers emissions and should remain at 4.2 tons per year.

11. The discussion under Rule 69.3.1 incorrectly identifies the thermal efficiencies as 32.7%. This rule defines "Stationary Turbine Engine" to mean "any gas turbine engine system, with or without power augmentation…"Therefore, the efficiency should relate to the entire combined-cycle system. In an e-mail submitted on June 28, applicant has provided a thermal efficiency for Palomar of 49% or better (HHV). This efficiency equates to an uncontrolled NOx emission level of 29.4 ppmv @ 15% O_2 and a controlled level of 17.6 ppmv @ 15% O_2. These levels should replace the current values in conditions 27 and 20, respectively.

Note, it is our understanding that the District is currently planning to revise this rule such that it would not apply during the commissioning period. If such a revision is adopted prior to completion of construction of the project, then a variance may no longer be necessary.

District Response: *The definition of "Stationary Turbine Engine" to mean "any gas turbine engine system, with or without power augmentation…" was intended to include any equipment that is an integral part of the combustion system (such* *as water injection). It was not intended to include post combustion equipment such as the HRSGs or duct burners. Therefore the appropriate thermal efficiency in this discussion is that of the engine. The thermal efficiency identified in the PDOC will remain unchanged.*

The District is currently planning to revise this rule to provide consideration of the commissioning period. If such a revision is adopted prior to completion of the project, the District agrees that a variance may no longer be necessary.

12. Section VI of the PDOC states that the "EPA has responsibilities under section 7 of the ESA for this project." If it is determined that the power plant has no potential for impact of endangered species, then the EPA would not be required to take any action under the ESA. The statement should be amended to read, "EPA may have responsibilities...."

    District Response: *The FDOC does not constitute a final PSD permit under 40* CFR 52.21 since *The United States Environmental Protection Agency (USEPA) is in consultation with the U.S. Fish and Wildlife Service (USFWS) pursuant to Section 7 of the Endangered Species Act (ESA). The consultation concerns the potential impact of the Palomar Energy Project on federally protected species. No date has been projected for issuance of the biological opinion nor USEPA's review of that opinion. Once the evaluation and determinations regarding Endangered Species issues have been completed, the District will issue a supplement to this FDOC as the final PSD permit. The final PSD permit may contain revised terms and conditions necessary to ensure compliance with PSD requirements, including those of the ESA*

13. Condition 9 requires that:

    > A Continuous Emission Monitoring System (CEMS) shall be installed and calibrated to measure and record the concentration of NOx and Co in the exhaust gas on a dry basis (ppmv) corrected to 15% oxygen and lb/hr and lb/MM BTU, and oxygen (O_2) in the exhaust gas. Upon initial firing and prior to final approval of the permanent CEMS, a portable CEMS, which has been properly calibrated, shall be used to continuously measure and record these conditions. The portable CEMS shall remain in full operation at all times when the turbine is in operation until the permanent CEMS has been installed and certified. The permanent CEMS shall thereafter be in full operation at all times when the turbines are in operation.

    It is unnecessary to record lb/hr and lb/MM BTU, as these are simple conversions and would more properly be only reported for maximum values to demonstrate compliance in the summary reports. Secondly, the wording implies that a portable CEMS would be an option if the permanent CEMS is not installed prior to initial startup.

The following alternative is suggested for this condition:

> A Continuous Emission Monitoring System (CEMS) shall be installed and calibrated to measure and record the concentration of NOx, CO and O_2 in the exhaust gas on a dry basis (ppmvd). Upon initial startup, a properly installed and calibrated CEMS shall thereafter be in full operation at all times when the turbines are in operation. If needed prior to installation and approval of the permanent CEMS, a portable CEMS, which has been calibrated, may be used to continuously measure and record these parameters. Within 90 days after commencement of commercial operations (as defined by 40 CFR 72.2), the CEMS shall be certified.

District Response: *If a permanent CEMS is not installed prior to initial startup the District agrees with the use of a portable CEMS. The District therefore agrees with the applicant's request and will make the changes in Condition 9 accordingly.*

14. Conditions 17 and 18 use the phrase "consecutive 12- calendar month period" while condition 19 uses the phrase "rolling 12-calendar month period". It is unclear if the District intends a difference between consecutive and rolling; if not, then the same term (i.e., rolling) should be used consistently. Also, it is unnecessary to repeat "12-month" in condition 18, so the following wording is suggested:

    The total aggregate emission of Volatile Organic Compounds (VOC) from all emission units at this stationary source shall not exceed 50 tons for each rolling 12- calendar month period. The VOC emissions shall begin accruing at the initial startup of each turbine. Compliance with this limit shall be based on District-approved source testing and the District-approved CO/VOC surrogate relationship.

    District Response: *The District agrees to use the phrase "rolling 12-calendar month period" in conditions 17, 18 and 19 to keep a consistent wording in these conditions. The FDOC will be amended accordingly.*

15. Since there is no limit on the number of regular vs. extended startups, separate definitions are not needed. Therefore, condition 40 should be deleted and condition 39 should be reworded as follows:

    > Startup shall be defined as the time necessary to reach minimum operating conditions for the air pollution control equipment and to meet the emission limits specified in conditions 31 and 32, not to exceed 4 hours.

Further, conditions 21, 22, and 27 should be amended to say "...startups and shutdowns... rather than specifying "...shutdowns and extended and regular startups."

District Response: *Because extended and regular startups have different duration periods, separate definitions are needed to make the distinction. If Palomar Energy agrees to give up the 4-hour duration for the extended startups, the District will not make the distinction between the two startups.*

16. It is unclear why condition 25 specifies "...or 200 hours"; this should be changed to 300 hours consistent with condition 23.

District Response: *The District has removed the 200 hour limit.*

17. Condition 36 reflects a 1-hour averaging time when operating without duct burners. While the District note (under condition 31) that this option is still under evaluation, this is inconsistent with condition 31 which requires a rolling 3-hour averaging time both with and without duct burners. Note, the emission limits given in this condition are incorrect, since the maximum hourly condition occur with low temperatures, and these levels reflect operation at the annual average temperature. Regardless, condition 36 should be deleted since it is unnecessary if the same concentration limits and averaging time are required and then the phrase "When operating with the burners" should be deleted from condition 37.

District Response: *The District evaluated CEMS data of a similar plant on the East Coast and has determined that a 1-hour averaging time was demonstrated when the equipment is operating without duct burner under certain conditions. The District has revised Condition 31 to include the appropriate averaging time.*

The limits used in condition 36 of the PDOC were imposed because they were used in emissions calculations, which affect the annual NOx emissions (or offsets). Because these limits are emissions at the annual average temperature, and do not affect AQIA, the District agrees to make the changes to reflect the maximum hourly conditions which occurs with low temperature (@ 20°F; NOx: 13.4 lbs/hr, CO: 16.3 lbs/hr, VOC 4.0 lbs/hr).

18. In Condition 43, the permit should allow for alternative source test methods to be approved upon review of the source test protocol. We suggest that the current wording be modified for each item (a, b, and c, and a separate line item for

ammonia) to include"... or equivalent as approved in writing by the Air Pollution Control Officer in advance." Item d should be modified to read:

e. Source testing shall be performed at no less than 80% of the maximum fired capacity at the given ambient conditions for the combine-cycle system.

District Response*: The District agrees and has made the appropriate changes*

19. The statement in condition 44 that " The source test shall demonstrate compliance with District Rule 1200 requirement for the gas turbines and duct burners" should be deleted. The rule requires that a Health Risk Assessment be performed, and specifies emissions control requirements depending on the results of the analysis. T-BACT for the Palomar project would be an oxidation catalyst, and since this control technology will be installed, the relevant cancer risk threshold in this rule is 10 in 1 million. Since the HRA for the project predicted a cancer risk of less than 1 in 1 million, compliance with this rule is assured.

District Response:

The District must confirm that assumptions made to perform the risk assessment are valid.

EPA COMMENTS

20. Palomar has not obtained all the 148.8 tons of NOx offsets necessary to satisfy the federal offset requirement. Palomar's November 2001 application only indicated " the Palomar project will offset NOx emissions with NOx ERCs and/or with an interpollutant trade of VOC ERCs, as allowed by SDAPCD rule 20.3(d)(8)." (p.8-17). The PDOC issued by the District states:

> "The applicant has identified at least 119.3 tons/year of additional existing or potentially available NOx credit. Based on the review to date, the applicant expects that the full 148.8 tons per year of NOx (equivalent) offsets can be provided prior to initial project startup."
> Page 35 of the PDOC for Palomar Energy Project

Finally, in a letter dated July 17, 2002, Palomar informed the District that the total purchased and contracted ERCs equaled 87.5 tons of NOX per year. This is far short of the 148.8 tons of NOx offsets that are required.

The District may not issue a final permit until Palomar identifies the source(s) of the remaining NOx ERCs and confirms these ERCs are federally enforceable as required by the federal Clean Air Act § 173. We are enclosing a copy of our policy on the timing of ERCs. In sum, EPA requires that ERCs be federally enforceable by the time the permit is issued and in effect by the time the new source commences operation.

District Response: *In a letter dated August 27, 2002, Palomar Energy has informed the District that it has 125.95 tons per year of ERCs purchased and in negotiation. The FDOC conditions will limit emissions accordingly. Furthermore the District has changed condition 17 to ensure that ERC's are federally enforceable.*

21. The District has not provided any analysis that demonstrates that the VOC ERCs, utilizing the District's interpollutant ratio of 2:1 at rule 20.3(d)(5(vi), will provide an adequate air quality benefit for this project. The PDOC states that, as of March 2002, 16.5 tons per year of VOC ERCs had been obtained to be substituted for NOx ERCs. The July 17, 2002 letter from Palomar Energy to the District does not specify the amount of VOC ERCs but only lists the "NOx equivalent" amount. Please provide a current summary of the total VOC ERCs obtained. In October 1997, we expressed general disagreement with the interpollutant trading ratio and the District's proposed methodology. We also identified the District's fixed interpollutant ratio of 2:1 as a deficiency in our August 6, 1999 proposed limited approval/disapproval of the District's NSR rule. While we may find that the ratio is adequate for the Palomar Energy Project, we believe that interpollutant trades should only be allowed if the trading ratio provides a net quality benefit. We would like to discuss this with you further before you issue the permit.

    District Response: *As of December 6, 2002, Palomar Energy owns 68.7 tpy NOx and 37.5 tpy of VOC, or 87.5 tpy of NOx and NOx equivalent.*

22. The District identified the NOx LAER limit for Palomar Energy Project as an unresolved milestone that would be resolved before the Final Determination of Compliance. At condition 31 of the PDOC, the District establishes a NOx limit of 2.0 ppm (3-hour average) but notes the condition may be revised pending continued evaluation of whether a NOx emission limit of 2 ppm, 1-hour average, with duct burners, has been demonstrated at similar plant on the East Coast.

    EPA believes that 2.0 ppm NOx LAER averaged over one hour, with and without duct burners in operation, has been achieved in practice. At least two similar combined-cycle power plant projects in California have been recently permitted at 2.0 ppm, one-hour average. First, on March 21, 2001 the California Energy Commission granted the application for certification for the Midway- Sunset

Power Project in Kern County, California with that limit. Second, on July 10, 2002 the Bay Area Air Quality Management District ("BAAQMD") issued its Final Determination of Compliance for the East Altamont Energy Center in which it stated that, "based upon our review of the CEM data for the ANP Blackstone power plant… we have concluded that a NOx emission rate of 2.0 ppmvd, @ 15% O_2, averaged over one hour, has been established as 'achieved in practice' BACT for NOx" (at page 9) Accordingly, BAAQMD imposed a condition of 2.0 ppm NOx @ 15% O_2, averaged over one hour as a permit condition. The BAAQMD also allowed certain operating periods where the source was not required to meet the 2.0 ppm limit so long as certain other conditions were met. (See condition # 21 FDOC, East Altamont Energy Center). Therefore, you must revise condition 31 to comply with the one-hour average.

District Response: *The power plants mentioned above by EPA except for the ANP Blackstone have not been built yet. The BACT/LAER determinations by the East Altamont Energy Center and the Midway-Sunset Power Project (Now Aera Energy LLC) were based on CEMS data from ANP Blackstone. The District has reviewed CEMS data for the first and second quarter 2002 and after consultations with the applicant is recommending a NOx LAER level of 2.0 ppm, 1-hour average except during duct burner operations and during certain transient conditions when a 2.0 ppm, 3-hour average limit will apply.*

BEFORE THE ENERGY RESOURCES CONSERVATION AND DEVELOPMENT COMMISSION OF THE STATE OF CALIFORNIA

IN THE MATTER OF:

APPLICATION FOR CERTIFICATION FOR THE PALOMAR ENERGY PROJECT

DOCKET NO. 01-AFC-24

PROOF OF SERVICE
(REVISED 10/22/02)

I, **Keith A. Muntz**, declare that on **December 17, 2002**, I deposited copies of the attached **Final Determination of Compliance (FDOC) dated December 6, 2002 from Air Pollution Control District, County of San Diego**, in the United States mail at ***Sacramento,*** *CA* with first class postage thereon fully prepaid and addressed to the following:

DOCKET UNIT

Send the original signed document plus the required 12 copies to the address below:

CALIFORNIA ENERGY COMMISSION
DOCKET UNIT, MS-4
Attn: Docket No. 01-AFC-24
1516 Ninth Street
Sacramento, CA 95814-5512

* * * *

Also send copies of all documents to:

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****Revisions to POS List, i.e. updates, additions and/or deletions.***

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I declare under penalty of perjury that the foregoing is true and correct

[signature]

Revisions to POS List, i.e. updates, additions and/or deletions.

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