Appendix F

Final Determination of Compliance for the Sutter Power Plant from FRAQMD; Dated Nov. 12, 1998

Sierra Nevada Customer Service Region

FEATHER RIVER AIR QUALITY MANAGEMENT DISTRICT

Serving the Counties of Yuba and Sutter
938 - 14th Street, Marysville, CA 95901
530/634-7659 FAX 530/634-7660 Burn Information 530/741-6299

Kenneth L. Corbin
Air Pollution Control Officer

cc: Mike Horn - Green [illegible]
Jon Marino - [illegible]
Curt [illegible] - [illegible]

December 11, 1998

Mr. Paul Richens
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

Dear Mr. Richens;

Enclosed is the errata for our November 13, 1998 Determination of Compliance for the Sutter Power Plant. Changes are in strike out/underline format.

We appreciate the cooperation we have received from all those involved in the processing of this application.

Best wishes for the holidays.

Sincerely,

Kenneth L. Corbin
Air Pollution Control Officer

KC/lac

cc: Jerry Salamy, CH2M Hill
Charlene Wardlow, Calpine Corporation
Steven Barhite, U.S. EPA
Richard Corey, CARB
a/c file

Errata for the Novemer 13, 1998
Final Determination of Compliance for the Sutter Power Plant, Yuba City, CA

~~November 13, 1998~~

Table of Contents

Introduction

On July 28, 1998 the Feather River Air Quality Management District (District) issued the PDOC for an Authority To Construct (ATC) Permit Application to Calpine Corporation (Applicant) for the proposed construction of a nominal 500 megawatt (MW), natural gas fired, two (2) combined cycle combustion turbine generators (CTGs), electric power generating facility to be designated as the Sutter Power Plant (SPP).

The ATC Permit Application (Application No. 13005A) included two (2) Westinghouse, Model 501F frame combined cycle CTGs, power train and ancillary equipment.

Per District Rule 10.1, this application has been reviewed and analyzed for consistency with all relevant District Rules and Regulations under the conditions of maximum air quality impacts or worst-case scenario.

This document is the Final Determination of Compliance (FDOC) of the proposed project and the District has determined that construction and operation will comply with all applicable District Rules and Regulations.

District response to comments received on the PDOC are included as Appendix A.

Copies of Emission Reduction Credit (ERC) evaluations are included as Appendix B.

2) Project Location

The SPP facility will be located in the northern portion of Sutter County, approximately 7.0 miles southwest of Yuba City, west of and adjacent to South Township Road and its interception with Best Road.

The Project will be located on 16 acres of a 77 acre parcel of land (Assessor's Parcel Number 21-230-25) adjacent to Calpine Corporation's cogeneration facility (Greenleaf 1). The plant will occupy 16 acres with the following legal description: the North half of the Northeast quarter of Section 24, Township 14 North, Range 2 East, Sutter County, California.

Access to the site from State Route (SR) 99 is via Oswald Road. Oswald Road is about 0.5 miles north of the site. Alternative access off SR 113 from the south is via George Washington Boulevard.

3) Project Description

Per Application No. 13005A, the SPP project will consist of a merchant electric power generation facility, nominally rated at 500 MW, totally fueled by means of natural gas and using a combined cycle system including two (2) CTGs, two (2) corresponding heat recovery steam generators (HRSGs); exhaust trains with an exhaust stack; a water treatment plant; a 230 kilovolt (kV) switching station; and approximately 4.0 miles of new 230 kV line that will connect with an existing Western Area Power Administration (WAPA) transmission line.

The plant will use California Public Utilities Commission (PUC) pipeline quality natural gas for fuel supplied via a Pacific Gas and Electric (PG&E) interstate transmission line. The natural gas is primarily methane, with a heating value of approximately 1,000 BTU per cubic foot.

Approximately 12 miles of new 16-inch diameter natural gas transmission line will be constructed. This new line will follow the existing gas line corridor that contains an 8-inch line currently supplying the Greenleaf 1 cogeneration facility.

Site preparation is expected to start in mid-1999 with commercial operation startup in late 2000.

4) Process Description

The SPP facility will use California PUC pipeline quality natural gas to fuel two (2) combined cycle CTGs and two duct burners. Each CTG is nominally rated at 170 MW, and by exhausting into two (2) HRSG units, steam will be generated in the HRSG units to produce an additional nominal 160 MW in a common steam turbine generator (STG) unit.

Power will be produced by both CTGs and the STG. Thermal energy produced in the CTGs by the combustion of natural gas will be converted into mechanical energy to generate electric power and drive the CTGs combustion air compressors.

Combustion air to the CTGs will flow through their corresponding intake air filter-evaporative cooler systems where the compression section of each CTG will increase the combustion air pressure before flowing to each corresponding turbine's set of dry low-NOx combustors.

Individual CTG hot combustion gases will expand through the corresponding electrical generator driver to generate power and the corresponding air compressor to increase its combustion pressure. Upon exiting, the CTG hot combustion gases will then enter each corresponding HRSG unit where they will heat feed water pumped to HRSG for steam generation.

The feed water will be converted to three (3) steam pressure levels to be delivered to the STG at high pressure (HP), intermediate pressure (IP), and low pressure (LP). The use of various pressure levels increases the cycle efficiency and flexibility.

HP steam delivered to the STG exits the HP section (cold reheat) and is combined with IP steam going through the reheater section of the HRSG. The mixed, reheated steam (hot reheat) is then introduced to the IP of the STG. The steam exiting this section of the STG is mixed with LP steam and used in the LP section of the STG.

LP steam leaving the STG passes through the surface condenser, where it gives up low temperature heat to cooling water and is condensed to liquid water. The cooling water flows through an air cooler system where the low-level heat is rejected into the atmosphere by a combination of forced air and natural convenction.

A maximum rate of 111,000 pounds (lb)/hour of steam from the portion of the HP steam exiting the HP section of the STG, will be injected downstream of the corresponding CTGs' dry low-NOx combustors to increase mass flow through the system and augment power production as required.

Each HRSG section will be equipped with duct burners to provide the flexibility of increasing STG power production and to provide for improved steam temperature control. These burners will only be fired with California PUC pipeline quality natural gas and will be sized for a maximum high heating value (HHV) of 170 million (MM)BTU per hour per HRSG.

Each CTG set will have a 145 feet high, 18 feet in diameter exhaust vent stack, from which controlled emissions will be discharged.

The air pollutants resulting from the operation of this facility will consist of NOx, CO, VOC, SO_2, and particulate matter 10 microns diameter (PM_{10}) or less emitted by the CTGs and duct burners.

These pollutants will be controlled by using clean burning California PUC pipeline quality natural gas, dry low-NOx combustors, low-NOx duct burners, SCR, and a high efficiency oxidation catalyst.

Each SCR will use anhydrous ammonia in conjunction with base metal catalyst modules to reduce NOx emissions from the corresponding exhaust vent stacks, which are the result of the CTGs and duct burners combustion operation. The catalytic reaction will convert NOx to nitrogen and water products.

The duct burners will be of the low-NOx type in order to minimize their contribution of NOx emissions that must be reduced by the SCR system.

4) Process Description (Continued)
~~(Continued)~~

Emissions of CO in the exhaust gases will be controlled using good combustor design and an oxidation catalyst. The oxidation catalyst will be located inside the corresponding HRSG and downstream of the SCR system ammonia injection. The catalytic reaction will convert CO to carbon dioxide (CO_2).

SO_2 emissions will be controlled by the use of California PUC pipeline quality natural gas in all fuel combustion operations.

VOCs and PM_{10} emissions from the CTGs and duct burners will be controlled by means of good combustor design, inlet filtration of combustion air, and the use of California PUC pipeline quality natural gas as fuel.

Each CTGs set exhaust vent stack will be equipped with CEMs in order to analyze and record exhaust gas flow rate, NOx concentration (by CEMs with dual scale capability), and percent oxygen (O_2). For monitoring the concentrations of CO, SO_2, PM_{10}, and VOCs in the exhaust gases, source test derived algorithms will be used.

5) Emissions Inventory

The following tables represent the District emissions calculations for the SPP facility. All documentation relating to the above mentioned minor adjustments are to be found in Appendix A.

Table - 5A - Duct Burner Maximum Hourly Emissions

Pollutants	Emission Factor	Uncontrolled Emissions (1)	Controlled Emissions
	(lb/MMBTU)	(lb/hr)	(lb/hr)
NOx (2)	0.08	13.6	1.4
CO (3)	0.1	17.0	3.4
VOC	0.012	2.0	2.0
SO_2	3.10E-05	0.01	0.005
PM_{10}	0.015	2.55	2.50

(1) Based on a heat input of 170 MMBTU/hr (HHV)
(2) Based on an SCR catalyst emission control factor of 0.10.
(3) Based on an Oxidation catalyst control factor of 0.20.

Table - 5B - Maximum Hourly Emissions based on 100% CTG load @ 20 ^{O}F, Duct Burner ON, and Power Augmentation ON@ 115 ^{O}F.

	CTG (1)	Duct Burner	Steam Injection
Pollutants	(lb/hr)	(lb/hr)	(lb/hr)
NOx	16.8	1.4	0.9
CO	16.7	3.4	14.2
VOC	1.5	2.0	0.01
SO_2	3.7	0.005	0.31
PM_{10} (2)	9.0	2.50	0.0

(1) Based on CTG NOx emission concentration 2.5 ppmvd @ 15% O_2.
(2) Based on Manufacturer guaranteed 9.0 Lb/hour of PM_{10} emissions, including sulfuric acid mist emissions. (per EPA Methods 201A and 202).

Table - 5C - Maximum Hourly Emissions for One CTG Hot Startups, Cold Startups, and Shutdowns

Pollutants	Hot Startup (1)	Cold Startup (1)	Shutdown (5)
	(lb/hr)	(lb/hr)	(lb/hr)
NOx	170	175	12.1
CO	902	838	12.6
VOC (2)(3)	1.1	1.1	1.1
SO_2 (3)	2.7	2.7	2.7
PM_{10} (3)(4)	9.0	9.0	9.0

(1) NOx and CO emission rates for Hot and Cold Startups are based at 61 ^{O}F ambient air per manufacturer's fax of 7/25/97.
(2) Applicant assumed that VOC emission rate = 20% of the unburned hydrocarbons (UBH) emissions rate from Black and Veatch (B&V's) material balance at 20 ^{O}F ambient air and 50% load.
(3) VOC, SO_2, and PM_{10} emissions rates are based on those from B&V's material balance at 20 ^{O}F ambient air and 50% load.
(4) Applicant assumed that PM_{10} emission rate is guaranteed at 9.0 lb/hr, and includes H_2SO_4 emissions (per EPA Methods 201A and 202).
(5) Applicant assumed that NOx and CO emission rates for Shutdown are based on those from B&V's material balance at 20 ^{O}F ambient air and 50% load.

5) Emissions Inventory (Continued)
~~(Continued)~~

Table - 5D - Maximum Hourly Emissions

	CTGs	Duct Burners	Steam Injections	Hot Startups	Cold Startups	Shutdowns
Pollutants	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)	(lb/hr)
NOx	33.5	2.7	1.8	339	349	24.1
CO	33.4	6.8	28.4	1,804	1,675	25.2
VOC	3.0	4.1	0.0	2.2	2.2	2.2
SO_2	7.4	0.0	0.6	5.3	5.3	5.3
PM_{10}	18.0	5.0	0.0	18.0	18.0	18.0

Table - 5E - Total Maximum Daily Emissions

	CTGs	Duct Burners	Steam Injections	Hot Startups	Cold Startups	Shutdowns	**Total Maximum Daily Emissions**
(hr/day) of Operation Per CTG	19	22	19	1	2	2	
Pollutants	(lb/day)	(lb/day)	(lb/day)	(lb/day)	(lb/day)	(lb/day)	(lb/day)
NOx	637	60	35	339	698	48	1,817
CO	635	150	539	1,804	3,351	50	6,528
VOC	57	90	0.42	2	4	4	158
SO_2	141	0.23	12	5	11	11	179
PM_{10}	342	109	0.0	18	36	36	541

Table - 5F - CTG Hourly Average Emissions used in Total Annual Emissions (1)

Pollutants	One CTG	Two CTGs
	Average (lb/hr)	Average (lb/hr)
NOx	16.3	32.6
CO	15.2	30.4
VOC	1.46	2.92
SO_2	3.59	7.2
PM_{10} (2)	9.0	18

(1) Based on B&V's material balance at 61 ^{O}F ambient air and 100% load and a NOx concentration of 2.5 ppmvd corrected to 15% oxygen without duct burner firing or steam injection.
(2) Includes sulfuric acid mist emissions (per EPA Methods 201A and 202).

Table - 5G - Total Annual Emissions

	CTGs	Duct Burners	Steam Injections	Hot Startups	Cold Startups	Shutdowns	**Total Annual Emissions**
(hr/year) of Operation Per CTG	8110	5460	2000	250	100	300	
Pollutants	(ton/year)	(ton/year)	(ton/year)	(ton/year)	(ton/year)	(ton/year)	**(ton/year)**
NOx	131.8	7.4	1.8	42.4	17.5	3.6	**204.6**
CO	123.3	18.6	28.4	225.5	83.8	3.8	**483.2**
VOC	11.8	11.1	0.0	0.3	0.1	0.3	**23.7**
SO_2	29.1	0.0	0.6	0.7	0.3	0.8	**31.5**
PM_{10}	73.0	13.6	0.0	2.3	0.9	2.7	92.4

6) Best Available Control Technology (BACT) Evaluations

Per the requirements of District Rule 10.1. E.1 (NSR Rule), the Applicant shall apply BACT to a new emissions unit that results in an emissions increase if the potential to emit (PTE) for the emissions unit equals or exceeds the following amounts:

Pollutant for all areas of the District	Pounds/Day
NOx	25
CO	500
SOx	80
ROC (ROG, VOC)	25
PM_{10}	80

Per Table - 5E, the SPP project's daily PTE will trigger application of BACT for all of the above pollutants.

NOx BACT

NOx, a precursor of PM_{10} and Ozone, will be formed as a result of the combustion of natural gas in the CTGs and the duct burners. The federal attainment status for the SPP site location is undefined for Ozone and attained for PM_{10}, while the state attainment status is non-attainment for both Ozone and PM_{10}.

District staff has reviewed the recent action of the South Coast AQMD, and recommendations by the United States Environmental Protection Agency (USEPA), California Energy Commission (CEC), and the California Air Resources Board (CARB) in defining a combustion turbine NOx BACT limit of 2.5 ppm, averaged over a one-hour period or 2.0 ppmvd @ 15% O_2, on a 3 hour rolling average. The Applicant has proposed as BACT for NOx, an SCR with ammonia injection with maximum NOx emissions of 2.5 ppmvd averaged over a 1-hour period, which is consistent with the recent SCAQMD BACT determinations and the recommendations of the USEPA, CEC, and CARB.

FRAQMD is aware that SCR vendors have issued guarantees for ammonia emissions as low as 5 ppmvd. First, the FRAQMD does not have statutory authority to perform a BACT analysis for ammonia, as ammonia is not a criteria pollutant and based on air dispersion modeling performed for the project does not pose a health concern. Furthermore, it is the opinion of the FRAQMD that limiting the SPP to 5 ppmvd of ammonia slip and a NOx concentration of 2.5 ppmvd @ 15% O_2 could result in ammonia emission limit exceedances as a result of controlling NOx emissions to this low level.

FRAQMD has determined a BACT limit for the SPP facility of a maximum NOx concentration of 2.5 ppmvd @ 15% O_2, on a 1 hour average, with a maximum concentration of ammonia in the controlled exhaust gases (ammonia slip) of 10 ppmvd @ 15% O_2. The Applicant is negotiating with the USEPA to develop Condition language to allow limited excursions above the maximum NOx concentration of 2.5 ppmvd @ 15% O_2.

CO BACT

CO is formed as a result of the incomplete combustion of natural gas in the CTGs and duct burners. Applicant has proposed to use as BACT, an oxidation catalyst with a vendor guaranteed 80% CO removal, resulting in maximum CO emissions of 4.0 ppmvd @ 15% O_2. The CARB has provided source test data showing that the oxidation catalyst proposed by SPP will likely result in CO concentrations considerable lower than the 4.0 ppmvd corrected to 15% O_2. These CO emissions data represent emissions from a "new and clean" CTG. The emission guarantees provided by the oxidation catalyst vendor represent the highest expected CO concentrations at the end of the oxidation catalyst systems useful life. Furthermore, the Applicant expects the oxidation catalyst system to perform comparably to the oxidation catalyst system represented by the source test data presented by the CARB. In light of this information, the District considers the proposed 4.0 ppmvd (corrected to 15% O_2) CO concentration to be acceptable for BACT.

6) Best Available Control Technology (BACT) Evaluations (Continued) ~~(Continued)~~

SO_2 BACT

Applicant has offered California PUC pipeline quality natural gas for all combustion operations as BACT, with a SO_2 emission limit of 1 ppmvd @ 15% O_2. The District considers this to be acceptable for BACT.

ROC BACT

Applicant proposed to use good combustion controls and an oxidation catalyst as BACT for a ROC emissions limit of 1 ppmvd @ 15% O_2. Based on source test data provided by the CARB, the oxidation catalyst proposed by the Applicant will likely result in ROC concentrations considerably lower than the 1.0 ppmvd corrected to 15% O_2 and comparable to the source test data provided by the CARB. In light of this information, the District considers the proposed 1.0 ppmvd (corrected to 15% O_2) ROC concentration to be acceptable for BACT.

PM_{10} BACT

For the CTGs and duct burners, Applicant offered California PUC pipeline quality natural gas for all combustion operations as BACT, with a PM_{10} emissions limit of: CTG = 9 pounds per hour and duct burner = 2.5 pounds per hour. The Applicant has assumed that 10 percent of the sulfur in the fuel will be converted to particulate matter and has included these sulfate emissions in the CTG particulate matter emission rate. This assumption is based on emission testing, using EPA Methods 201A and 202, and thermodynamic analysis performed by the CTG vendor. The District considers the exclusive use of California PUC pipeline quality natural gas to be acceptable for BACT.

7) Assessment of Class 1 Area Visibility Protection

Since no Class I areas exist within 100 kilometers of the SPP project, no Class I area impact analysis is required.

8) Assessment of Air Quality Impact Analysis

Applicant has submitted the results of a District approved SCREEN3 revised air dispersion model to reflect the change in height of the exhaust vent stacks to 145 feet, the District's NOx 2.5 ppmvd BACT determination and the replacement of the wet cooling tower with an air cooler.

The modeled maximum concentration values obtained were compared to the promulgated Significant Criteria values in order to assess the air quality impact that the proposed SPP project will have in the area of concern (see Table 8-1)

Table 8-1 Comparison of Maximum Modeled Concentration to Significant Criteria

Pollutant	Averaging Period	Modeled Maximum Concentration (1) (ug/m^3)	Class II Significant Impact Criteria (ug/m^3)	Percent of Significance Criteria (Percent)
NO_2	Annual	1.1	1	110
SO_2	3 hour	1.4	25	5
SO_2	24 hour	0.6	5	12
SO_2	Annual	0.1	1	10
PM_{10}	24 hour	0.71	5	14
PM_{10}	Annual	0.138	1	14
CO	1 hour	69.4	2,000	3.5
CO	8 hour	48.6	500	10

Where: (1) Modeled impacts estimated from 1 hour concentrations using the conversion factors from the U. S. EPA document – *"Screening Procedures for Estimating the Air Quality Impact of Stationary Source"*.

The model results offer proof that the SPP project will not result in a significant ambient air quality impact for SO_2, PM_{10}, and CO.

However, refined modeling performed for NOx as indicated on Table 8-2 below, indicates that the project does not result in either a violation nor contribute significantly to a violation of an ambient air quality standard (AAQS). The results presented in Table 8-2 represent the results of the revised refined modeling analysis.

The PM_{10} impacts, when added to a background concentration that exceeds the AAQS indicate a continued violation of the AAQS. However, the Applicant is providing emission reduction credits to mitigate the project's PM_{10} emissions at a ratio larger than 1 to 1.

Table 8-2 Comparison of Maximum SPP Operational Impacts to the AAQS

Pollutant	Averaging Period	Maximum Impacts (ug/m^3)	Background Concentration (1) (ug/m^3)	Total Impact (ug/m^3)	AAQS Standard (ug/m^3)	Percent of AAQS (Percent)
NO_2	1 hour	241.2 (4)	150.4	391.6	470 (3)	83
NO_2	Annual	0.26	31.96	32.2	100 (2)	32
SO_2	3 hour	1.3.	26.1	27.4	1,300 (2)	2
SO_2	24 hour	0.6	7.83	7.89	105 (3)	8
SO_2	Annual	0.1	0.0	0.1	80 (2)	0.1
PM_{10}	24 hour	0.55	154	154.55	50 (3)	309
PM_{10}	Annual	0.097	36.7	36.8	30 (3)	123
$PM_{2.5}$ (5)	24 hour	0.55	154	154.55	65 (2)	238
$PM_{2.5}$ (5)	Annual	0.097	36.7	36.8	15 (2)	245
CO	1 hour	1,243 (4)	11.4	1254	23,000 (3)	6
CO	8 hour	305.2 (4)	8.3	314	10,000	3

Where: (1) Is based on the highest recorded concentration at the Yuba City CARB monitoring station.
(2) A Federal Standard.
(3) A State Standard.
(4) Is based on startup emissions.
(5) Assumed that $PM_{2.5}$ concentration is the same as PM_{10}.

9) Health Risk Assessment Evaluation

The SPP facility will use and store anhydrous ammonia for use in the SCR system. The Applicant states in the ATC that the facility will store a maximum of 12,000 gallons of anhydrous ammonia and that a Risk Management Plan (RMP) will be prepared per the requirements of 40 CFR Part 68.

10) Offset Requirements

Per District Rule 10.1, the SPP project's area status and the air contaminant emissions expected from the facility require mitigation in the form of offsets for those pollutants and their precursors for which the area is designated as non-attainment.

The SPP site area's non-attainment air contaminants are NOx and VOCs, as precursors of O_3, and PM_{10}.

Furthermore, per District Rule 10.1, any new source with a PTE of non-attainment air contaminants or their precursors, in excess of 25 ton per year, must provide mitigation by offsetting such emissions in excess of 25 tons per year, using ERCs. However, the District will require mitigation of 100 percent of the project's emissions since this project is considered a modification to an existing facility (Calpine 1).

Table 10-1 below indicates the expected Total Annual Emissions and the corresponding ERC liabilities for the SPP facility.

Table 10-1 ERCs Offsets Liabilities

Pollutants	Total Annual Emissions (Ton per Year)	ERCs Liability (Ton per Year)
NOx	205	205
VOCs	23.7	23.7
PM_{10}	92.4	92.4

Table 10-2 presents the ERC facility name and location, the Air District, the ERC Certificate Number, the method of ERC generation, the distance of the ERC source from the SPP facility, and the offset distance ratio.

The identity of several of the ERC holders has not been disclosed because of Applicant's stated confidential nature of this information.

Tables 10-3 through 10-5 present the NOx, VOC, and PM_{10} ERCs (excluding offset distance ratios) either held under contract by the Applicant or in negotiations to purchase by the Applicant, on a calendar quarterly basis.

Tables 10-6 through 10-8 present the NOx, VOC, and PM_{10} ERCs available to the Applicant after discounting for the offset distancing ratio and the SPP ERC liabilities for the same pollutants.

As presented in these Tables, the Applicant has proposed to mitigate PM_{10} emissions through the paving of unpaved roads. The Applicant has an agreement with Sutter County for road paving to provide these ERCs. The District will require all such road paving to be completed prior to startup of the SPP facility.

These Tables demonstrate that the Applicant has adequate ERCs to mitigate the SPP ERC liabilities.

10) Offset Requirements (Continued)

~~(Continued)~~

Table 10-2 Emission Reduction Credit Sources Under Contract or in Negotiations

Facility Name	ERC Location	Air District	ERC Certificate Number	Method of ERC Generation	Distance from SPP Miles	Offset Distance Ratio
Atlantic Oil Co.	Yuba City, CA	Feather River AQMD	95-1	Shutdown and removal of natural gas engine compressors	<20	1.2
Confidential	Brannan Island, CA	Sacramento Metropolitan AQMD	0020	Shutdown and removal of natural gas engine compressors	68	2.0
Confidential	Brannan Island, CA	Sacramento Metropolitan AQMD	287/288	Shutdown and removal of natural gas engine compressors	68	2.0
Rosboro Lumber	Marysville, CA	Feather River AQMD	94-1	Shutdown of wood fired boiler	<20	1.2
Confidential	Sutter County	Feather River AQMD	98-101	Shutdown and removal of natural gas engine compressors	<20	1.2
Confidential	Sutter County	Feather River AQMD	992024	Shutdown and removal of natural gas engine compressors	<20	1.2
Road Paving	Sutter County	Feather River AQMD	NA	Paving of Unpaved Roads	<20	1.2

Table 10-3 Calendar Quarterly NO_X Emission Reduction Credits Held by ERC Sources Excluding Offset Distance Ratios

Facility Name	January -March	April-June	July-September	October-December	Total NO_X ERC	
					Total Pounds	Total Tons
Atlantic Oil Co.	10,955	10,955	10,955	10,955	43,820	21.9
Confidential (ERC#20)	47,556	16,277	50,263	95,947	210,042	105
Confidential (ERC#287/288)	70,096	101,314	67,266	25,389	264,064	132
Rosboro Lumber	21,134	21,134	21,134	18,850	82,252	41.1
Confidential (ERC#98-1)	3,334	3,371	3,408	3,408	13,521	6.8
Confidential (ERC#992024)	16,986	16,986	16,986	16,986	67,944	34
Total ERCs Per Quarter	**170,061**	**170,037**	**170,012**	**171,535**	**681,643**	**340.8**

Table 10-4 Calendar Quarterly VOC Emission Reduction Credits Held by ERC Sources Excluding Offset Distance Ratios

Facility Name	January-March	April-June	July-September	October-December	Total VOC ERC	
					Total Pounds	Total Tons
Atlantic Oil Co.	2,526	2,526	2,526	2,526	10,104	5.0
Confidential (ERC #287/288)	1,443	1,442	1,443	3,346	7,674	3.8
Rosboro Lumber	10,567	10,567	10,567	9,425	41,126	20.6
Confidential (ERC #992024)	261	261	261	261	1,045	0.52
Total ERCs Per Quarter	**14,797**	**14,796**	**14,797**	**15,558**	**59,949**	**29.92**

10) Offset Requirements (Continued)
(~~Continued~~)

Table 10-5 Calendar Quarterly PM_{10} Emission Reduction Credits Held by ERC Sources Excluding Offset Distance Ratios

Facility Name	January-March	April-June	July-September	October-December	Total ~~NO_X~~ PM_{10} ERC	
					Total Pounds	Total Tons
Rosboro Lumber	14,861	14,644	13,561	13,178	56,244	28.1
Road Paving (Estimated)	40,579	40,796	41,879	42,262	165,516	82.8
Total ERCs Per Quarter	**55,440**	**55,440**	**55,440**	**55,440**	**221,760**	**110.9**

Table 10-6 Proposed NO_X Mitigation for the Sutter Power Plant (Adjusted for Distance Ratios)

Facility Name	January-March	April-June	July-September	October-December	Total NO_X ERC	
					Total Pounds	Total Tons
Atlantic Oil Co.	9,129	9,129	9,129	9,129	36,516	18.3
Confidential (ERC#20)	23,778	8,138	25,131	47,973	105,021	52.5
Confidential(ERC#287/288)	35,048	50,657	33,633	12,694	132,032	66.0
Rosboro Lumber	17,612	17,612	17,612	15,708	68,543	34.3
Confidential (ERC#98-1)	2,778	2,809	2,840	2,840	11,268	5.6
Confidential (ERC#992024)	14,155	14,155	14,155	14,155	56,620	28.3
Total Quarter ERCs	**102,500**	**102,500**	**102,500**	**102,500**	**410,000**	**205**
SPP ERC Liability	**102,500**	**102,500**	**102,500**	**102,500**	**410,000**	**205**

Table 10-7 Proposed VOC Mitigation for the Sutter Power Plant (Adjusted for Distance Ratios)

Facility Name	January-March	April-June	July-September	October-December	Total VOC ERC	
					Total Pounds	Total Tons
Atlantic Oil Co.	2,105	2,105	2,105	2,105	8,420	4.2
Confidential (ERC #287/288)	722	721	722	1,673	3,837	1.9
Rosboro Lumber	8,806	8,806	8,806	7,854	34,272	17.1
Confidential (ERC #992024)	218	218	218	218	871	0.44
Total Quarter ERCs	**11,850**	**11,850**	**11,850**	**11,850**	**47,400**	**23.7**
SPP ERC Liability	**11,850**	**11,850**	**11,850**	**11,850**	**47,400**	**23.7**

Table 10-8 Proposed PM_{10} Mitigation for the Sutter Power Plant (Adjusted for Distance Ratios)

Facility Name	January-March	April-June	July-September	October-December	Total PM_{10} ERC	
					Total Pounds	Total Tons
Rosboro Lumber	12,384	12,203	11,301	10,982	46,870	23.4
Road Paving (Estimated)	33,816	33,997	34,899	35,218	137,930	69
Total Quarter ERCs	**46,200**	**46,200**	**46,200**	**46,200**	**184,800**	**92.4**
SPP ERC Liability	**46,200**	**46,200**	**46,200**	**46,200**	**184,800**	**92.4**

11) District and Other Rules and Regulations - Compliance Evaluation

District Specific Applicable Rules and Regulations:

Rule 2.13 - Nuisance.
Facility shall not discharge from any source whatsoever such quantities of air contaminants or other materials which cause injury, detriment, nuisance or annoyance to any considerable number of persons or to the public or which endanger the comfort, repose, health or safety of any such person or the public or which cause or have a natural tendency to cause injury or damage to business or property.

Since the facility will exclusively use California PUC pipeline quality natural gas as fuel, is located in a relatively isolated area, and provided air pollution control equipment, the SPP project is expected to meet the Nuisance Rule.

Rule 3.0 - Visible Emissions.
Facility shall not emit visible emissions for a period or periods aggregating more than 3 minutes in any one hour as dark or darker in shade as that designated as No. 2 on the Ringlemann Chart, as published by the United States Bureau of Mines; or of such opacity as to obscure an observers view to a degree equal to or greater than does smoke described above.

Since the facility will exclusively use California PUC pipeline quality natural gas as fuel the SPP project is expected to meet the Visible Emissions Rule.

Rule 3.2 - Particulate Matter Concentration.
Facility shall not discharge into the atmosphere from any source particulate matter in excess of 0.3 grains per cubic foot of gas at standard conditions. When the source involves a combustion process, the concentration must be calculated to 12 per cent carbon dioxide (CO_2).

Since the facility will exclusively use California PUC pipeline quality natural gas as fuel the SPP project is expected to meet the Particular Matter Concentration Rule.

Rule 3.3 - Dust and Fumes.
Facility shall not discharge in any one hour from any source whatsoever fumes in total quantities in excess of the amounts as prescribe for and shown in District's Rule 3.3 Table of Allowable Rate of Emission Based on Process Weight Rate.

Since the facility will exclusively use California PUC pipeline quality natural gas as fuel the SPP project is expected to meet the Dust and Fumes Rule.

Rule 3.10 – Sulfur Oxides.
A facility shall not discharge into the atmosphere from any single source of emission whatsoever, any sulfur oxides in excess of 0.2 percent by volume (2,000 ppm) collectively calculated as sulfur dioxide (SO_2).

Since facility will exclusively use California PUC pipeline quality natural gas as fuel the SPP facility is expected to meet the Sulfur Oxides Rule.

Rule 3.13 Circumvention.
A facility shall not be build, erect, install, or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of the Health and Safety Code of the State of California or of these Rules and Regulations.

Based on review of the SPP application, the SPP facility is expected to meet the Circumvention Rule.

11) District and Other Rules and Regulations - Compliance Evaluation (Continued) ~~(Continued)~~

Rule 3.16 Fugitive Dust Emissions.
A facility shall take every reasonable precaution not to cause or allow the emissions of fugitive dust from being airborne beyond the property line from which the emission originates, from any construction, handling or storage activity, or any wrecking, excavation, grading, clearing of land or solid waste disposal operation. Reasonable precautions shall include, but are not limited to: Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, construction of roadways, or the clearing of land; Application of asphalt, oil, water, or suitable chemical on dirt roads, material stockpiles, and other surfaces which can give rise to airborne dusts; Other means approved by the Air Pollution Control Officer.

During the facility's site preparation and construction phases, fugitive dust emissions will be mitigated as described in the ATC. Since facility's operation does not significantly contribute to fugitive dust emissions, the SPP facility is expected to meet the Fugitive Dust Emissions Rule.

Rule 9.1 Emission Monitoring.
The Air Pollution Control Officer may require the owner or operator of any air contaminant source to install, use and maintain monitoring equipment: sample emissions; establish and maintain records; and make periodic emission reports. All of these actions shall be accomplished in a manner approved by the Air Pollution Control Officer.

Since the facility's permit will be conditioned to require CEMS to track emission concentrations of NOx and O_2 and algorithms in combination with periodic source testing for tracking CO, VOCs, SOx, and PM_{10} the SPP project is expected to meet the Emission Monitoring Rule.

Rule 9.2 Records and Reports.
Air Pollution monitoring records and such fuel composition data as deemed necessary shall be recorded, compiled and submitted on forms furnished by the Air Pollution Control Officer.

Since facility's permit will be conditioned as to the type and frequency of record keeping, and reporting must be maintained and filed with the District, the SPP project is expected to meet the Records and Reports Rule.

Rule 9.3 Tests.
All tests shall be made and the results calculated in accordance with test procedures approved by the Air Pollution Control Officer. All tests shall be made under the direction of persons qualified by training and experience in the field of air pollution control and approved by the Air Pollution Control Officer.
The Air Pollution Control Officer may conduct tests of emissions of air contaminants from any source.
Upon request of the Air Pollution Control Officer, the person responsible for the source to be tested shall provide necessary holes in stacks or ducts and such other safe and proper sampling and testing facilities, exclusive of instruments and sensing devices as may be necessary for proper determination of the emission of air contaminants.

Since facility's permit will be conditioned to perform source tests and test procedures will be specified, the SPP project is expected to meet the Tests Rule.

11) District and Other Rules and Regulations - Compliance Evaluation (Continued) ~~(Continued)~~

Rule 9.5 Air Pollution Equipment – Scheduled Maintenance.
In the case of shut-down or re-start of air pollution equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least twenty-four (24) hours prior to the planned shutdown. Such prior notice may include, but is not limited to the following:
(a) Identification of the specific facility to be taken out of service as well as its location and permit number;
(b) The expected length of time that the air pollution control equipment will be out of service;
(c) The nature and quantity of emissions of air contaminants likely to occur during the shut-down period;
(d) Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period;
(e) The reasons that it would be impossible or impractical to shut down the source operation during the maintenance period:
During the testing period moderate emission of air pollution may be allowed.

Since facility's permit will be conditioned per the above regulation, the SPP project is expected to meet the Air Pollution Equipment – Scheduled Maintenance Rule.

Rule 9.6 Equipment Breakdown.
In the event that any emission source, air pollution control equipment, or related facility breaks down in such a manner which may cause the emission of air contaminants in violation of this article, the person responsible for such equipment shall immediately notify the Air Pollution Control Officer of such failure or breakdown and subsequently a written statement giving all pertinent facts, including the estimated duration of the breakdown. The Air Pollution Control Officer shall be notified when the condition causing the failure or breakdown has been corrected and the equipment is again in operation.

Since facility's permit will be conditioned per the above regulation, the SPP project is expected to meet the Equipment Breakdown Rule.

Rule 10.1.E.1 New Source Review - Best Available Control Technology.
Applicant shall apply BACT to any new emissions unit that results in an emissions increase if the potential to emit for the emissions unit equals or exceeds the following amounts:

Pollutant for all areas of the District	*Pounds/Day*
NOx	*25*
CO	*500*
SOx	*80*
ROC (ROG, VOC)	*25*
PM_{10}	*80*

Since Applicant has applied BACT to all emission units that trigger the above emission rates, the SPP project is expected to meet the Best Available Control Technology Rule.

Rule 10.1.E.2.a New Source Review – Offsets.
Emission reductions shall be sufficient to offset calendar quarter emission increases of non-attainment pollutants or their precursors associated with a new or modified stationary source and shall be determined as follows:

a. Offsets shall be required for a new stationary source with potential to emit, calculated pursuant to Section F.3, non-attainment pollutants or their precursors equal to or exceeding 25 tons per year.
The amount of offsets required shall be at least equal to that portion of the potential to emit which exceeds 25 tons per year.

The facility must provide offsets for NOx, ROC, and PM_{10}, (see Tables 10-1 to Table 10-8). Based on letters of intent submitted, Applicant has sufficient contractual ERCs to provide for source location and interpollutant offset ratios. Since the Applicant must meet all ERC requirements prior to commencement of the facility construction, the SPP project is expected to meet the Offsets Rule.

11) District and Other Rules and Regulations - Compliance Evaluation (Continued) ~~(Continued)~~

Rule 10.1.E.2.c.2 New Source Review – Location of Offsets and Offsets Ratios.
Offsets, which are obtained from a source, located, in another Air District may be used only if the provisions of H & S Code Section 40709.6 are met and the involved Air Districts enter into an agreement formalized by a memorandum of understanding.

Applicant has included in the contractual ERCs, offsets that are available from sources located in the Sacramento Metropolitan Air Quality Management District (SMAQMD). The District will condition the DOC to require a memorandum of understanding prior to start of construction of the SPP facility.

Therefore, the SPP project is expected to meet the Location of Offsets and Offsets Ratios Rule.

Rule 10.1.E.2.d New Source Review – Interpollutant Offsets.
The APCO may approve the substitution of one air contaminant for another air contaminant to meet the requirement for offsetting an emission increase on a case-by-case basis, provided that the Applicant demonstrates to the satisfaction of the APCO, through the use of an impact analysis, that the emission increases from the new or modified source will result in a net air quality benefit and will not cause or contribute to a violation of any air quality standard.

Based on recommendations by CEC, CARB, and USEPA the District has revised its VOC (ROC) / NOx interpollutant offset ratio to 2.0 to 1.0.

The SPP project is expected to meet the interpollutant offset ratio rule.

Rule 10.1.E.2.g New Source Review – Compliance with Other Owned, Operated, or Controlled Sources.
The owner or operator of a proposed new source shall certify to the APCO that all major stationary sources, which are owned or operated by such person (or by any entity controlling, controlled by, or under common control with such a person) in California which are subject to emission limitations are in compliance, or on a schedule for compliance, with all applicable emission limitations and standards.

Applicant has provided the above certification, therefore, SPP project is in compliance with the Other Owned, Operated, or Controlled Sources Rule.

Rule 10.1.G New Source Review – Air Quality Impact Analysis.
In no case shall emissions from new or modified emissions unit cause or make worse the violation of an ambient air quality standard. The APCO may require an applicant to use an air quality model to estimate the effects of a new or modified emissions unit or facility.

Applicant has satisfactorily performed, in section 10 of the DOC, the required Air Quality Impact Analysis per the requirements of the APCO. Therefore, the SPP project is compliance with the Air Quality Impact Analysis Rule.

Rule 10.2.D.2.c.5 - Emission Reduction Credit Banking – Eligibility of Emission Reductions.
(D.2) For emission reductions occurring after February 8, 1993, the following criteria must be met in order to deem such reductions eligible for banking:
(c) For non-permitted emission units the following shall apply:
(5) If the District, pursuant to state laws, cannot permit the emission unit, the source creating ERCs shall execute a legally binding contract between the applicant and the owner or operator of such offset source, which by its terms, shall be enforceable by the District. Any such permit or contract shall contain enforceable conditions, which ensure that the emission reductions will be provided in accordance with the provisions of this Rule, and shall continue for the reasonably expected life of the proposed source.

Applicant has proposed to pave a number of Sutter County unpaved roads to potentially mitigate some or all of their PM_{10} offset liabilities. The District will condition this FDOC to require Applicant to provide, prior to start of construction, a copy of an executed legally binding contract between applicant and Sutter County that ensures the maintenance of said roads by the County and which provides enforceable conditions and ensures that the emission

11) District and Other Rules and Regulations - Compliance Evaluation (Continued) ~~(Continued)~~

Reductions will be provided in accordance with the provisions of the Non-Permitted Emission Units Rule. Therefore, the SPP project is expected to meet the Eligibility of Emission Reductions Rule.

Rule 10.3.C.1 Federal Operating Permits – Sources Subject to Rule 10.3.
C.1 Sources Subject to Rule 10.3
The sources listed below are subject to the requirements of Rule 10.3:

- *(a) A major source;*
- *(b) A source with an acid rain unit for which application for an Acid Rain Permit is required pursuant to Title IV of the CAA;*
- *(c) A solid waste incinerator subject to a performance standard promulgated pursuant to section 111 or 129 of the CAA;*
- *(d) Any other source in a source category designated, pursuant to 40 CFR Part 70.3, by rule of the U.S. EPA ; and*
- *(e) Any source that is subject to a standard or other requirement promulgated pursuant to section 111 or 112 of the CAA, published after July 21, 1992, designated, pursuant to 40 CFR Part 70.3, by the U.S. EPA at the time the new standard or requirement is promulgated.*

The SPP facility falls under category (a), (b), and (e) above, therefore the SPP project meets the applicability criteria of the Federal Operating Permits Rule.

Rule 10.3.D.2.a.4.a) Federal Operating Permits – Application Requirements.
D.2 Application Requirements.
a. Initial Permit:

- *3. For a source that becomes subject to Rule 10.3 after the date the rule becomes effective, an owner or operator shall submit a standard District application within 12 months of the source commencing operation.*
- *4. For a source with an acid rain unit, an owner or operator shall submit a standard District application and acid rain permit applications to the District. The applications shall be submitted within the following time frame:*
  - *(a) If the source is subject to Rule 10.3 because of section C.1a above, within the applicable timeframe specified in sections D.2.a.3. above.*

The Applicant states in the ATC that within 12 months of the initial operating date of the facility it will file a Federal Operating Permit and that it will file an Acid Rain permit application 24 months prior to the commencement of facility operation.

Therefore, the SPP project is expected to meet the Federal Operating Permits - Application Requirements Rule.

Other Applicable Rules and Regulations:

AB2588, Toxic Hot Spots.
Facilities with criteria pollutant air emissions in excess of 10 ton per year are required to prepare and submit to the District a Toxic Hot Spots emission inventory.

Applicant has provided a Health Risk Assessment which indicates that the facility will represent no significant health risk to the public. The first SPP Toxic Hot Spots emission inventory will be due on the month of August following the first full calendar year of operational history. It is expected that the SPP project will meet the requirements of the AB2588, Toxic Hot Spots Regulation.

Prevention of Significant Deterioration.
District does not have delegated authority for the PSD Program. However, the District is aware that the Applicant has filed a PSD permit application with U.S. EPA Region – IX that has been deemed complete.

11) District and Other Rules and Regulations - Compliance Evaluation (Continued) (Continued)

Standards of Performance for New Stationary Sources.
District does not have delegated authority for the Standards of Performance for New Stationary Sources Program. However, the Applicant states in the ATC that the facility is subject to the NSPS Subparts A, Db, and GG and that it will comply with said requirements. Permit will be conditioned to meet all of the above NSPS requirements, therefore, it is expected that the SPP project will meet NSPS Regulation.

Title III, Maximum Achievable Control Technology.
There are no promulgated national emission standards for hazardous air pollutants (NESHAPS) nor maximum achievable control technology (MACT) for Combustion Turbines (other than BACT/LEAR which the SPP project is expected to meet). However, the District is aware that the USEPA has recently began to develop (NESHAPS) for Combustion Turbines and that they are not expected to establish these final NESHAPS until November 15th, 2000. It is expected that the SPP project will meet present Title III requirements.

Title IV, Acid Rain.
The Acid Rain provisions are applicable to the SPP facility. The requirements are tracking and monitoring the emissions of SO_2 and NOx and to establish an emission allowance-trading program.
Since facility exclusively uses California PUC pipeline quality natural gas as fuel, it is exempt from installation of SO_2, CO_2, volumetric flow rate, and opacity CEMS. However, the facility must: 1) Submit an Acid Rain permit; 2) Comply with SO_2 and NOx emission limitations; 3) Obtain emissions allowances, and 4- Install, operate, and certify CEMS for NOx and O_2. Applicant states in the ATC that the Acid Rain permit will be filed 24 months before operational startup and that CEMS meeting the requirements of (4) above will be certified within 90 days after operational startup. Therefore, it is expected that the SPP project will meet the Title IV requirements.

Risk Management.
The facility would store approximately 12,000 gallons of anhydrous ammonia and therefore be subject to the provisions of 40 CFR Part 68 that requires the preparation and implementation of a Risk Management Plan (RMP).

It is expected that a RMP will be filed with Sutter County prior to actual storage of anhydrous ammonia and therefore the project would meet the requirements of 40 CFR Part 68.

12) ATC Permit Conditions

All equipment necessary for the operation of the SPP project will be under one ATC. The permit conditions are presented in two sections:

The 1st section presents the General ATC Permit Conditions which are common permit conditions applying to all operations. The 2nd section presents the Specific ATC Permit Conditions specific to the SPP.

12) A. General ATC Permit Conditions

(a) Facility shall not discharge from any source whatsoever such quantities of air contaminants or other materials that cause a public nuisance.

(b) Facility shall not emit particulate emissions from any single source which exceeds an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor.

(c) Facility shall not discharge into the atmosphere from any source particulate matter in excess of 0.3 grains per cubic foot of gas at standard conditions. When the source involves a combustion process, the concentration must be calculated to 12 per cent carbon dioxide (CO_2).

(d) Facility shall not discharge in any one hour from any source whatsoever fumes in total quantities in excess of the amounts as prescribed for and shown in District's Rule 3.3 Table of Allowable Rate of Emission Based on Process Weight Rate.

(e) Facility shall not discharge into the atmosphere from any single source of emissions whatsoever any sulfur oxides in excess of 0.2 percent by volume (2,000 ppm) collectively calculated as sulfur dioxide (SO_2).

(f) ~~Applicant~~ Project owner shall not be build, erect, install, or use any article, machine, equipment or other contrivance, to ~~the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or~~ conceals an emission which would otherwise constitute a violation of the Health and Safety Code of the State of California or of ~~District's~~ these Rules and Regulations.

g) Applicant shall take every reasonable precaution not to cause or allow the emissions of fugitive dust from being airborne beyond the property line from which the emission originates, from any construction, handling or storage activity, or any wrecking, excavation, grading, clearing of land or solid waste disposal operation. Reasonable precautions shall include but are not limited to use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, construction of roadways, or the clearing of land; application of asphalt, oil, water, or suitable chemicals on dirt roads, material stockpiles, and other surfaces which can give rise to airborne dusts; and other means approved by the APCO.

(h) In the case of shutdown or re-startup of air pollution control equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least twenty-four (24) hours prior to the planned shutdown. Such prior notice may include but is not limited to the following:

- (h1) Identification of the specific equipment to be taken out of service as well as its location and permit number:
- (h2) The expected length of time that the air pollution control equipment will be out of service:
- (h3) The nature and quantity of emissions of air contaminants likely to occur during the shut-down period:
- (h4) Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period:
- (h5) The reasons that it would be impossible or impractical to shut down the source operation during the maintenance period.

12) A. General ATC Permit Conditions (Continued) ~~(Continued)~~

(i) In the event that any emission source, air pollution control equipment, or related facility breaks down in such a manner which may cause the emission of air contaminants in violation of any permit condition or applicable rules or regulations, other than as exempted herein, the applicant shall immediately notify the APCO of such failure or breakdown and subsequently provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. The APCO shall be notified when the condition causing the failure or breakdown has been corrected and the equipment is again in operation.

(j) Applicant shall apply for a Title V Federal Operating Permit within 12 months after operational startup.

(k) Applicant shall prepare and submit to the District an Air Toxic Hot Spots emission inventory by the first month of August following the first full calendar year of facility operational history.

(l) A PSD permit must be obtained from the USEPA before commencement of facility operations.

(m) The equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions), Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Systems), and GG (Standards of Performance for Stationary Gas Turbines). Compliance with all applicable provisions of these regulations is required.

(n) Applicant shall meet the provisions of the Federal Acid Rain Program Title-IV by filing an Acid Rain permit 24 months before operational startup and by certifying CEMS for NOx and O_2 within 90 days after operational startup.

(o) Applicant shall file an RMP with the Sutter County office in charge of the prevention of accidental releases and record a copy of -same with the District prior to operational startup.

(p) This ATC is not transferable from one location to another, or from one person to another without the written approval of the APCO.

(q) District personnel shall be allowed access to the plant site and pertinent records at all reasonable times for the purposes of inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emission records and otherwise conducting all necessary functions related to this permit.

(r) Applicant shall maintain a copy of all District permits at the facility.

(s) Combustion turbine exhaust stacks shall exhaust at a height of 145 feet and the maximum diameter shall not exceed 18 feet.

(t) ~~Applicant~~ Project owner shall submit to the District and the Energy Commission ERC option contracts or final signed contracts~~agreements~~ for the project's ~~all~~-ERC~~'s~~ liability, except PM10, as listed in ~~Tables 10-1~~Condition 12) B. (k) ~~of this DOC,~~ prior to ~~commencement of construction~~Energy Commission's final Decision on the project.

u) The following Sutter County roads and corresponding miles are to be paved prior to operational startup of the project by the Project owner ~~by Applicant~~ in order to obtain PM_{10} ERC credits:

Roads	Length to be Paved (Miles)
McClatchy	0.7
Schlag	0.5
Boulton	3.5
Pierce	0.9

(u1) The location and distance of the roads above may be changed provided that the total offset PM_{10} ERC credits remain the same, and that the District and ~~CPM~~ Energy Commission ~~is~~ are notified, in writing, prior to the start of the project construction.

12) A. General ATC Permit Conditions (Continued) ~~(Continued)~~

(u2) ~~Applicant~~ Project owner shall provide, prior to start of construction, a copy of an executed legally binding contract between ~~applicant~~ project owner and Sutter County that ensures the maintenance of said roads and which provides conditions enforceable by the District.

v) Applicant has produced evidence indicating that it has an enforceable right to ERCs located in another District. These ERCs cannot be used until the District Board adopts an approving resolution and enters into an MOU with the other District. The District intends to act on the resolution and MOU as soon as practicable after CEC completes an environmental analysis document, assuming the criteria in Section 15253, Subdivison (b), of the CEQA Guidelines are met.

(w) Applicant may substitute interpollutant offsets of VOCs (ROCs) for NOx at a 2.0 to 1.0 interpollutant offset ratio pursuant to Rule 10.1, Section E.2. d.

(x) The facility shall exclusively use California PUC pipeline quality natural gas as fuel. The fuel gas total sulfur and heat content will be determined and reported to the District by collecting and analyzing a sample on a monthly basis or by providing monthly certification of the natural gas total sulfur and/or heat content issued by the natural gas distributor.

(y) All basic and control equipment is to be operated and maintained in accordance with vendors' recommended practices and procedures.

12) B. Specific ATC Permit Conditions

(a) The maximum heat input allowed to each permitted internal and external combustion emissions unit, expressed in MMBtu units on a High Heating Value basis (HHV), shall not exceed the limits indicated in the table below:

Emission Unit	MMBtu/hour ~~(1)~~	MMBtu/day (1~~2~~)	MMBtu/year (2~~3~~)
CTG-1	1,900	45,600	16,644,000
CTG-2	1,900	45,600	16,644,000
Duct Burners-1	170	4,080	928,200
Duct Burners-2	170	4,080	928,200

~~(1)Based on an hourly average~~
~~(2)~~(1) Based on a 24 hour-~~calendar~~ day
~~(3)~~(2) Based on 365 days/~~calendar~~ year

(b) The following definitions and limitations shall apply:

(b1) Startups are defined as the time period commencing with the introduction of fuel flow to the gas turbine and ending when the NOx concentrations do not exceed 2.5 ppmvd at 15% O_2 averaged over 1-hour.

(b2) Cold Startups are those that occur after the CTG has not been in operation for more than 72 hours.

(b3) For each CTG, the Cold Startup shall not exceed 180 consecutive minutes.

(b4) Hot Startups are startups that are not Cold Startups.

(b5) The maximum allowable NOx emissions for Hot and Cold Startups from each CTG shall not exceed 519 lb/day.

(b6) For each CTG, the Hot Startup shall not exceed 60 consecutive minutes.

12) B. Specific ATC Permit Conditions (Continued) ~~(Continued)~~

(b7) Shutdowns are defined as the time period commencing with a 15 minute period during which the 15minute average NOx concentrations exceed 2.5 ppmvd at 15% O2 and ending when the fuel flow to the gas turbine is discontinued.

(b8) For each CTG, the Shutdown shall not exceed 60 consecutive minutes.

(b9) The maximum duration of Cold Startups per CTG shall be 150 hours per year and 39 hours per calendar quarter.

(b10) The maximum duration of Hot Startups per CTG shall be 250 hours per year, and 63 hours per calendar quarter.

(b11) The maximum duration of Shutdowns per CTG shall be 300 hours per year, and 76 hours per calendar quarter.

(b12) Compliance with the above yearly limits shall be calculated based on a rolling 12 month average.

(b13) All emissions during startups and shutdowns shall be included in all calculations of daily and annual mass emissions required by this permit.

(b14) For each CTG the maximum number of Duct Burner hours of operation shall not exceed 5,460 per calendar year.

(b15) For each CTG the maximum number of Power Augmentation Steam Injection hours shall not exceed 2,000 per calendar year.

(b16) For each CTG the ~~maximum~~ hourly emissions in ~~rates (lbs/hr) (~~for a cold startup (not to exceed 120 minutes of uncontrolled emissions) are given in the table below and shall be averaged over any rolling three hour period, except for the NOx emissions ~~rate~~, which ~~will~~ shall be averaged over a one hour period:

Pollutants	Maximum Hourly Emissions ~~(lb/hr)~~						
	CTG	CTG + Duct Burner	CTG + Duct Burner + Steam Injection	CTG + Steam Injection	Hot Start Up	Cold Start Up	Shut Down
NOx	16.8	18.2	19.1	17.7	170	175	~~175~~12.1
CO	16.7	20.1	34.3	30.9	902	838	~~838~~12.6
VOC	1.5	3.5	3.51	1.51	1.1	1.1	1.1
SO_2	3.7	3.71	4.02	4.01	2.7	2.7	2.7
PM_{10}	9	11.5	11.5	9	9	9	9

~~Note that these maximum hourly rates are based on Table — 5D — Emission Inventory.~~

(b18~~7)~~ ~~For each CTG the m~~Maximum ~~calendar~~ daily emissions in ~~rates (lbs/day)~~ are given in the table below:

Pollutants	~~Maximum~~ ~~Daily~~ Total Emissions ~~for 1~~Per CTG ~~(lb/day)~~	Calpine Maximum SPP Dailiy Emissions
Nox	909	1,817
CO	3,264	6,528
VOC	79	158
SO_2	90	179
PM_{10}	271	541

~~Note that these maximum daily rates are based on Table 5E Emission Inventory.~~

12) B. Specific ATC Permit Conditions (Continued) ~~(Continued)~~

(b18) The maximum quarterly emissions rates for the facility are given in the table below:

Pollutants	January-March (lb/quarter)	April-June (lb/quarter)	July-September (lb/quarter)	October-December (lb/quarter)
NOx	102,500	102,500	102,500	102,500
CO	241,600	241,600	241,600	241,600
VOC	11,850	11,850	11,850	11,850
SO_2	15,750	15,750	15,750	15,750
PM_{10}	46,200	46,200	46,200	46,200

~~Note that these maximum quarterly rates are based on Table 5G Emission Inventory.~~

(b19)- The maximum annual calendar year emissions in ~~rates~~ (tons/year) for the facility are given in the table below:

Pollutants	Total Emissions Per CTG	Total ~~Maximum~~ Calpine ~~Annual SPP~~ Emissions for the facility ~~(ton/year)~~
NOx	102	205.86
CO	242	483.16
VOC	11.9	24.4~~13.7~~
SO_2	15.7	31.5
PM_{10}	46.2	92.54

~~Note that these maximum annual rates are based on Table 5G Emission Inventory.~~

(c) BACT Emission Limits

The BACT emission limits (including duct burners emissions) specified in Conditions (c1), (c2), (c3), (c4), and (c5) apply under all operating load rates except during CTG startups and shutdowns, as defined in Conditions (b1) through (b12).

(c1) NOx emission concentrations shall be limited to 2.5 ppmvd @ 15% O_2 on a 1 hour rolling average (based on readings taken at 15 minute intervals) and with a maximum of 10 ppmvd ammonia slip.

(c2) CO emission concentrations shall be limited to 4.0 ppmvd @ 15% O_2,on a calendar day average.

(c3) VOC emission concentrations shall be limited to 1 ppmvd @ 15% O_2, on a calendar day average.

(c4) PM_{10} emissions shall be limited to 11.5 pounds per hour, on a calendar day average.

(c5) SO_2 emission concentrations shall be limited to 1 ppmvd @ 15% O_2, on a calendar day average.

Prior to commencing operations, the applicant may propose provisions related to short-term excursions during which NOx emissions might exceed levels specified in condition (c1) under limited, specified conditions.

(d) Each CTG set exhaust vent stack shall be equipped with NOx and % oxygen (O_2) CEMs in order to analyze and record exhaust gas flow rate and concentrations. CO, PM_{10}, SO_2, and VOC emissions shall be monitored by the CEMs, using source test derived algorithms as indicated in (e) below. In the event that test results show that CO emission limits are exceeded, the APCO may require CEMs for recording concentrations of CO.

12) B. Specific ATC Permit Conditions (Continued) ~~(Continued)~~

(d1) The NOx CEMs shall have the capability of recording NOx concentrations during all operating conditions, including startups and shutdowns.

(d2) Relative accuracy testing shall be performed on the CEMs on a semi-annual basis or as required by the Acid Rain requirements in Title 40, CFR, Part 75, Appendix B.

(e) Within ninety days after commercial operation of the SPP, source testing shall be performed to determine the mass emission rates and concentrations of NO_X, CO, VOC, and SO_2 emissions at four different steady-state CTG load rates over the expected operating range of either combustion turbine, as required by 40 CFR 60.335.c (2). The source testing will be used to determine compliance with the permitted emission limits indicated in Specific ATC Permit Conditions (b) and (c). Source testing shall be conducted to determine PM_{10} mass emissions and concentrations while the CTG is operating at 100 percent load with and without the duct burners, firing at the maximum rated capacity or 170 MMBtu/hr (HHV), whichever is greater.

(e1) The source testing results shall be used to develop predictive emission algorithms to estimate mass emission rates for CO, VOC, and SO_2, and PM_{10} emissions.

(e2) Source testing to determine the mass emission rates and concentrations of NOx shall be conducted annually after the initial source test indicated in e) above.

(e3) Source testing to determine the mass emission rates and concentrations of CO, VOC, SO_2 and PM_{10} shall be conducted annually. The Air Pollution Control Officer may waive annual source testing requirements if prior test results indicate an adequate compliance margin has been maintained.

(f) A source test to determine ammonia slip shall be conducted within ninety days after commercial operation of the SPP and thereafter as required by the APCO.

(g) The maximum allowable ammonia injection rate to each of the SCR systems shall be 25 pounds per hour under normal operating conditions. This injection rate may be adjusted based on source tests results.

(h) Within ninety days after beginning commercial operation of the SPP, cold startup, hot startup, and shutdown source tests shall be conducted to determine the emissions of CO and NOx. The APCO may approve the use of the NOx CEMs readings in lieu of source testing if annual Relative Accuracy Testing Audits (RATA) testing is provided.

(i) Records and logs of all data generated by CEMS and algorithms shall be maintained for a period of five (5) years.

(j) Applicant shall provide calendar quarterly reports to the District in a format determined in consultation with the District. The calendar quarterly reports shall include the following: CEMS and predictive algorithm emissions data; CTG and duct burner fuel use and operating hours; power augmentation steam injection rates and hours of operation; ammonia injection rates; emission control systems and CEMS hours of operation including the time, date, duration, and reason for any malfunctions of these systems; the number of hot startups, cold startups, and shutdowns; and the electrical and steam production rates. These data shall be averaged on a daily basis, except where required to demonstrate compliance with an emission limitation.

12) B. Specific ATC Permit Conditions (Continued)

(k) Prior to the start of construction, t~~T~~he SPP facility must provide ERC certificates for NOx, ~~R~~VOC, and PM_{10}, as indicated in the table below~~, prior to commencement of the facility operation~~. The ERC sources are Atlantic Oil Company, PG&E, Tri Union, and Rosboro Lumber (a portion of required PM_{10} ERCs and offsets are to be provided pursuant to condition 12)A.u.). Alternative sources of offsets may be used if they meet the criteria applied to these sources and are approved by the District and the Energy Commission.

Mitigation Offsets for the Sutter Power Plant

	January-March Pounds	April-June Pounds	July-September Pounds	October-December Pounds	Total ~~NOx-~~ERCs and Offsets	
					Total Pounds	Total Tons
Required NOx	170,061~~102,500~~	170,037~~102,500~~	170,012~~102,500~~	171,535~~102,500~~	681,643~~410,000~~	340.82~~205~~
Required VOC	14,797~~11,850~~	14,796~~11,850~~	14,797~~11,850~~	15,558~~11,850~~	59,949~~47,400~~	29.92~~23.7~~
Required PM_{10}	55,440	55,440	55,440	55,440	221,760	110.9
~~Required PM_{10}~~ ~~46,200~~ ~~46,200~~ ~~46,200~~ ~~46,200~~ ~~184,800~~ ~~92.4~~These ERCs are based on the appropriate offset distance ratio calculations.						

13) District Conclusions

The District has reviewed the proposed SPP project's ATC application and determined that the proposed project, after application of the ATC Permit Conditions given in section 12) above, will comply with all applicable FRAQMD Rules and Regulations.

14) Public Comments

All comments regarding this FDOC shall be addressed and forward to:

Mr. Kenneth L. Corbin
Air Pollution Control Officer
Feather River Air Quality Management District
938 14th Street
Marysville, CA 95901

Copies of above comments shall be also addressed and forward to:

Mr. David Howekamp, Director
Office of Air Division
Attention: Mr. Matt Haber, Chief
Permits Office
United States EPA, Region IX
75 Hawthorne Street
San Francisco, CA 94105

Mr. Peter Venturini, Chief
Stationary Sources Division
Executive Office
California Air Resources Board
P.O. Box 2815
Sacramento, CA 95812

Mr. Paul Richins
Project Manager
California Energy Commission
1516 9th Street
Sacramento, CA 95814-5512

Mr. Curt Hildebrand
Project Director
Calpine Corporation
50 West San Fernando Street
San Jose, CA 95113

15) GLOSSARY of TERMS

AAQS - Ambient air quality standard

AB – Assembly Bill

APCO - Air Pollution Control Officer

ATC – authority to construct

BACT – Best Available Control Technology

BTU - British Thermal Units

B&V - Black and Veatch

CAA – Clean Air Act

CARB – California Air Resources Board

CEMS – Continuous Emission Monitoring System

CFR – Code of Federal Regulations

CO – Carbon Monoxide

CO_2 – Carbon Dioxide

CTG – combustion turbine generator

ERCs - Emission Reduction Credits

FDOC – final determination of completion

FRAQMD – Feather River Air Quality Management District

gpm - gallons per minute

H & S – Health and Safety

HHV – high heating value

HP – high pressure steam

HRSG – heat recovery steam generator

hr/day – Hours per day

hours/day – Hours per day

hours/week – Hours per week

hours/year – Hours per year

IP – intermediate pressure steam

15) GLOSSARY of TERMS (Contintued) ~~(Continued)~~

ROG – Reactive Organic Gases

SCR – selective catalytic reduction

SOx – Sulfur Oxides

SO_2 – Sulfur Dioxide

SPP - Sutter Power Plant

SR – State route

STG – steam turbine generator

ton/year – Tons per year

UBH - Unburned Hydrocarbons

USEPA – U. S. Environmental Protection Agency

ug/m^3 – Microgram per cubic meter

VOC – Volatile Organic Compounds

WAPA - Western Area Power Administration

^oF – Degrees Fahrenheit

Appendix G

Revised Air Quality Testimony for the Sutter Power Plant; Dated Nov. 17, 1998

Sierra Nevada Customer Service Region

STATE OF CALIFORNIA—THE RESOURCES AGENCY

PETE WILSON, *Governor*

CALIFORNIA ENERGY COMMISSION
1516 NINTH STREET
SACRAMENTO, CA 95814-5512

November 17, 1998

Sutter Proof of Service List

RE: REVISED AIR QUALITY TESTIMONY FOR THE SUTTER POWER PROJECT

The enclosed air quality testimony replaces the testimony contained in the Final Staff Assessment/Draft Environmental Impact Statement (FSA/Draft EIS) for the Sutter Power Project filed on October 19, 1998 (97-AFC-2/DOE/EIS-0294). The testimony incorporates the conditions of certification contained in the Final Determination of Compliance provided by the Feather River Air Quality Management District.

Please remove page 77 through 110 of the FSA/Draft EIS and replace with the enclosed testimony dated November 17, 1998.

Paul R

PAUL RICHINS, JR.
Project Manager

PROOF OF SERVICE (REVISED ________) FILED WITH
[illegible] ON 11/17/98

AIR QUALITY

Testimony of Magdy Badr

INTRODUCTION

This analysis addresses the potential air quality impacts resulting from criteria air pollutant emissions created by the construction and operation of the Sutter Power Plant Project (SPP). Criteria air pollutants are those for which a state or federal standard has been established. They include nitrogen dioxide (NO2), sulfur dioxide (SO2), carbon monoxide (CO), ozone (O3) and its precursors (NOx and VOC), volatile organic compounds (VOC), particulate matter less than 10 microns in diameter (PM10) and its precursors: NOx, VOC, SOx, and lead (Pb).

In carrying out its analysis, the California Energy Commission staff identifies the potential air quality impacts associated with the SPP, evaluates the project's conformance with all applicable air quality laws, ordinances, regulations and standards (LORS), evaluates the adequacy of proposed mitigation measures and the need for alternative or additional mitigation measures, and proposes specific conditions of certification, including those recommended by the local air pollution control district (California Code Regs., Title 20, Section 1742(b), 1742.5(b), and 1744(b)).

Staff addresses the following questions:

- whether the project is likely to conform with applicable air quality laws, ordinances, regulations and standards,
- whether the process equipment and the pollution control devices are properly sized and will perform their functions as expected,
- whether the project is likely to cause significant adverse environmental effects, including new violations or contributions to existing violations of the applicable ambient air quality standards,
- whether any identified air quality impacts are adequately mitigated, and
- whether any specific project configurations, gas turbines, or control devices, alone or in combination, will result in lesser impacts to the environment, and thus can be considered as potential mitigation measures for air quality impacts.

The air quality regulatory agencies involved in the review of the SPP, including the Feather River Air Quality Management District (District), the California Air Resources Board (CARB), and the U.S. Environmental Protection Agency (EPA), Region IX, and the commission staff, have participated in resolving all of the potential air quality issues associated with the project. The District has issued its Final Determination of Compliance on the project and staff has finalized their recommendations.

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal New Source Review (NSR) program, which is administered by the District requires the SPP to comply with the Lowest Achievable Emission Rate (LAER) for NOx, VOC and CO and to provide offsets for emissions of these pollutants. In addition, Calpine must certify that all facilities they own and operate comply with applicable requirements contained in the State Implementation Plan. The Environmental Protection Agency (EPA) has revoked the one hour ozone standard for the northern portion of Sutter County in which the SPP will be located, as of July 1998, and it has been replaced by the new 8-hour ozone standard. However, the existing District NSR rules will remain in effect until rules based on the new 8-hour ozone standard are developed and adopted. Therefore, the Calpine project must still comply with all existing Federal NSR rules.

The SPP facility is located in an attainment area for NO2, SO2 and CO, and is subject to the Prevention of Significant Deterioration (PSD) review for those air contaminants. In general, the project must comply with Best Available Control Technology (BACT) for NO2, SO2 and CO and demonstrate that its emission impacts will not significantly degrade the existing ambient air quality in the region. EPA Region IX retains PSD review authority. The PSD trigger levels are 40 tons per year for NOx, CO, VOC and SO2 and 15 tons for PM10. The SPP is subject to PSD review for NOx, CO and PM10 since the annual emission levels are higher than the PSD trigger levels.

The power plant's gas turbines are also subject to the federal New Source Performance Standards (NSPS). These standards include a NOx emissions of no more than 75 ppm at 15 percent excess oxygen (ppm@15%O2), and a SOx emissions of no more than 150 ppm@15%O2.

States are required by Title V of the Federal Clean Air Act (FCAA) to implement and administer the operating permit programs with the goal of ensuring that large sources are in compliance with all applicable requirements. These requirements are contained in Title 40 CFR, part 70. To comply with Title V, the District has the authority to administer the federal operating permit program and has adopted Regulation X, Rule 10.3. The Acid Rain Provisions of the FCAA establish an emission allowance/tracking program and impose monitoring of SO2 and NOx emissions. All electrical generating facilities labeled as "affected units" are subject to acid rain regulations. The SPP is subject to acid rain regulations and must comply with all requirements. Calpine will estimate SO2 emissions using the approved emission factors and measured heat input rate. The CO2 emissions are estimated using a carbon balance for natural gas and measured heat input. The heat input will be monitored on a continuous basis with an accuracy of $\pm$ 2 percent. The heat content of the natural gas will be measured or certified monthly by the natural gas distributor. Furthermore, the SPP will be required to install, operate and certify NOx continuous emission monitoring systems (CEMS). All calculation methodologies and CEMS must be installed and certified within 90 days following the commencement of the operation of the power plant. However, since the

SPP will utilize natural gas in its operation, the project is exempted from the installation of CEMS for SO2, CO2 and volumetric flow rate. The following AIR QUALITY Table 1 summarizes the federal and state ambient air quality standards and the averaging time for each pollutant.

STATE

The California State Health and Safety Code, Section 41700, requires that "no person shall discharge from any source whatsoever such quantities of air contaminants or other material which causes injury, detriment, nuisance, or annoyance to any considerable number of persons or to the public, or which endanger the comfort, repose, health, or safety of any such persons or the public, or which cause, or have a natural tendency to cause, injury or damage to business or property".

LOCAL

The following is a concise summary of the major applicable District Rules and Regulations:

Regulation III, Rule 3.0	Prohibits a person from discharging visible emissions greater than Ringleman No. 2, which is equivalent to 40 percent opacity.
Regulation III, Rule 3.2	Prohibits a person from discharging particulate matter in concentrations greater than 0.3 grains per cubic foot of gas at standard conditions.
Regulation III, Rule 3.10	Prohibits a person from discharging sulfur oxides in excess of 0.2 percent by volume (2,000 ppm), collectively calculated as SO2.
Regulation III, Rule 3.16	Regulates operations which periodically may cause fugitive dust emissions into the atmosphere.
Regulation IV	Defines the authority to construct and permit to operate processes associated with stationary emission sources.
Regulation X, Rule 10.1	Defines the New Source Review process, including best available control technology (BACT) requirements, and ambient air quality impact assessment and emission reduction credit requirements.

AIR QUALITY Table 1
Federal and State Ambient Air Quality Standards

Pollutant	Averaging Time	Federal Standard	California Standard
Ozone (O_3)	1 Hour	0.12 ppm (235 µg/m^3)	0.09 ppm (180 µg/m^3)
Carbon Monoxide (CO)	8 Hour	9 ppm (10 mg/m^3)	9 ppm (10 mg/m^3)
	1 Hour	35 ppm (40 mg/m^3)	20 ppm (23 mg/m^3)
Nitrogen Dioxide (NO_2)	Annual Average	0.053 ppm (100 µg/m^3)	—
	1 Hour	—	0.25 ppm (470 µg/m^3)
Sulfur Dioxide (SO_2)	Annual Average	80 µg/m^3 (0.03 ppm)	—
	24 Hour	365 µg/m^3 (0.14 ppm)	0.04 ppm (105 µg/m^3)
	3 Hour	1300 µg/m^3 (0.5 ppm)	—
	1 Hour	—	0.25 ppm (655 µg/m^3)
Suspended Particulate Matter (PM10)	Annual Geometric Mean	—	30 µg/m^3
	24 Hour	150 µg/m^3	50µg/m^3
	Annual Arithmetic Mean	50 µg/m^3	—
Sulfates (SO_4)	24 Hour	—	25 µg/m^3
Lead	30 Day Average	—	1.5 µg/m^3
	Calendar Quarter	1.5 µg/m^3	—
Hydrogen Sulfide (H_2S)	1 Hour	—	0.03 ppm (42µg/m^3)
Vinyl Chloride (chloroethene)	24 Hour	—	0.010 ppm (26 µg/m^3)
Visibility Reducing Particulates	1 Observation	—	In sufficient amount to produce an extinction coefficient of 0.23 per kilometer due to particles when the relative humidity is less than 70 percent.

Regulation X, Rule 10.3 Requires the preparation and submittal of Title V operating permit and acid rain permit applications. Applications for new sources are due within 12 months of initial operation of the source.

Regulation XI, Rule 11.3 Restricts the use of hexavalent chromium water treatment chemicals in cooling towers. Limits hexavalent chromium emissions to existing cooling towers.

SETTING

METEOROLOGY AND CLIMATE

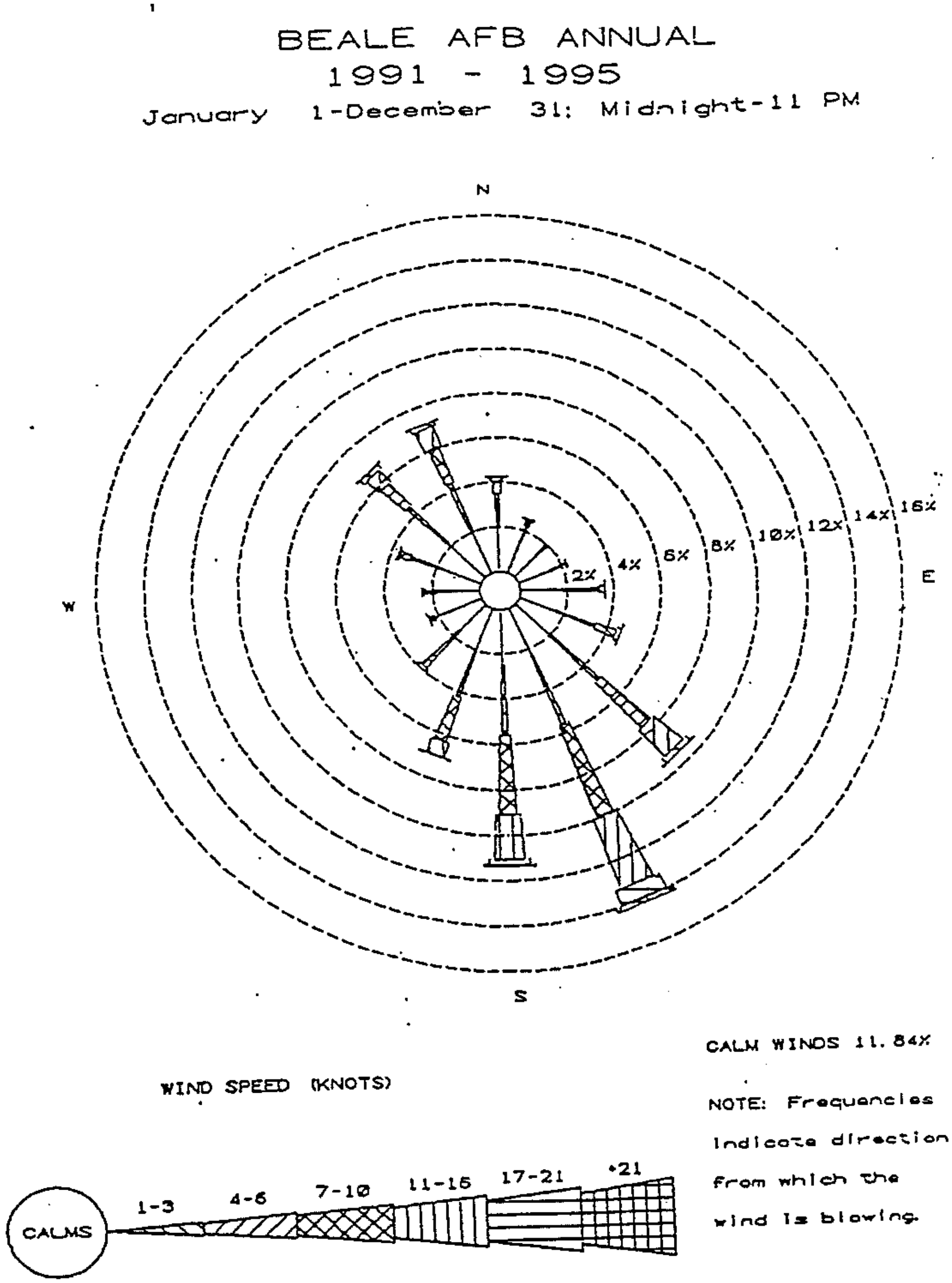
The SPP will be located in Sutter County, approximately seven miles southwest of Yuba City, California. It will be constructed on a twelve acre parcel adjacent to the Greenleaf Unit 1 cogeneration facility. The area surrounding the project site is flat. The Sutter Buttes is the nearest elevated terrain, which is located nine miles northeast of the project site.

Sutter County is part of the Sacramento Valley Air Basin, which is surrounded by the Coastal Mountain Range to the west, the Sierra Nevada to the east, the Cascade Range to the north and the San Joaquin Valley Air Basin to the south. The Sacramento Valley has a moderate mediterranean climate, which is characterized by hot, dry summers and cool, rainy winters. The annual average rainfall is approximately 17 inches. The majority of the rain falls from October to April. The North Pacific storm track intermittently dominates the Valley weather, with periods of dense and persistent low-level fog often occurring between storms. The frequency and persistence of heavy fog in the Valley diminishes with the approach of spring, when the days lengthen and the intensity of the sun increases.

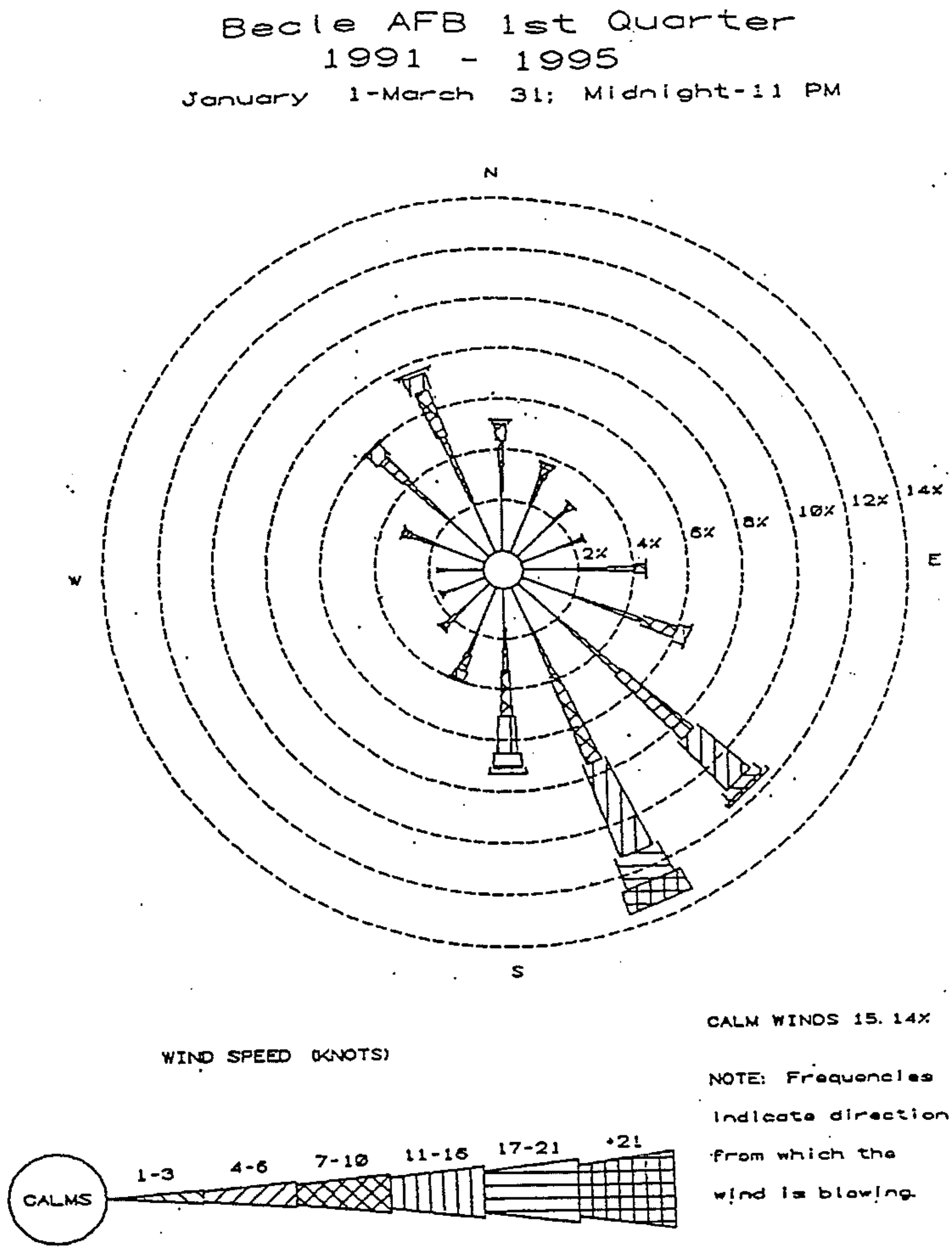
During the summer, the Pacific storm track is usually north of the Sacramento Valley, the afternoon temperatures are warm to hot, while nights are usually mild due to cool marine air intrusion from the San Francisco Bay Area. Meteorological data collected at the Sacramento Executive Airport (which is over 30 miles away from the project site) indicate that July is usually the warmest month of the year, with a normal daily maximum temperature of 93°F, and a normal daily minimum of 59°F. In the fall and spring, the afternoon temperatures are mild, in the 60's and 70's, while nights are cool, in the 40's and 50's. In the winter, temperatures are cool in the afternoon and crisp at night. The coldest month is usually January, with a normal daily maximum of 53°F and a normal daily minimum of 38°F. The recorded high temperature is 115°F and the recorded low temperature is 18°F.

The prevailing wind is southerly during most of the year. However, in November and December, a large north to south pressure gradient develops over Northern California and northerly winds prevail. Wind directions are often influenced by the topography of the Central Sacramento Valley and the surface pressure gradient between the coast and the Valley. Figures 1 through 5 show the annual and quarterly Windroses

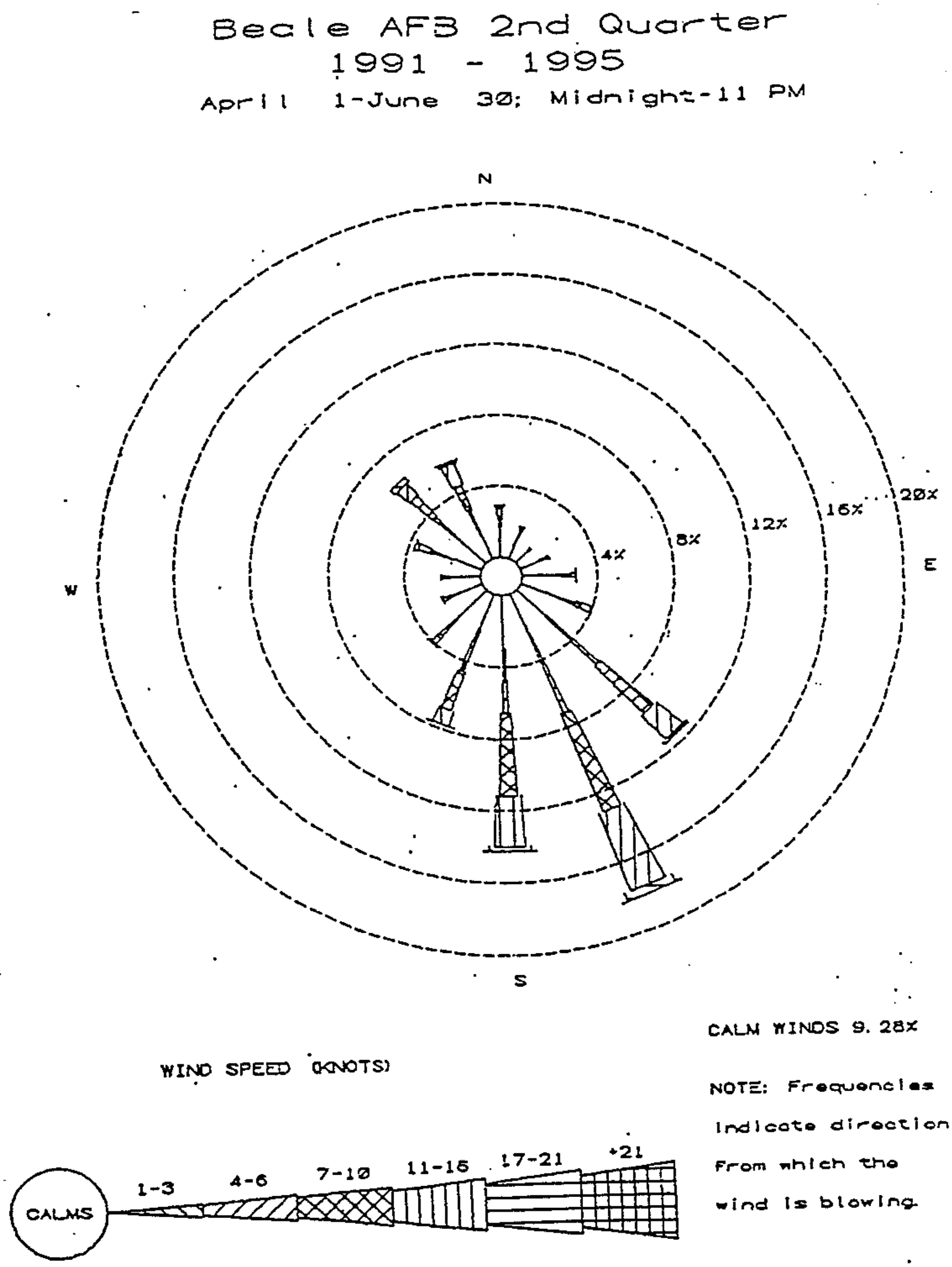
AIR QUALITY Figure 1
Windrose Annual



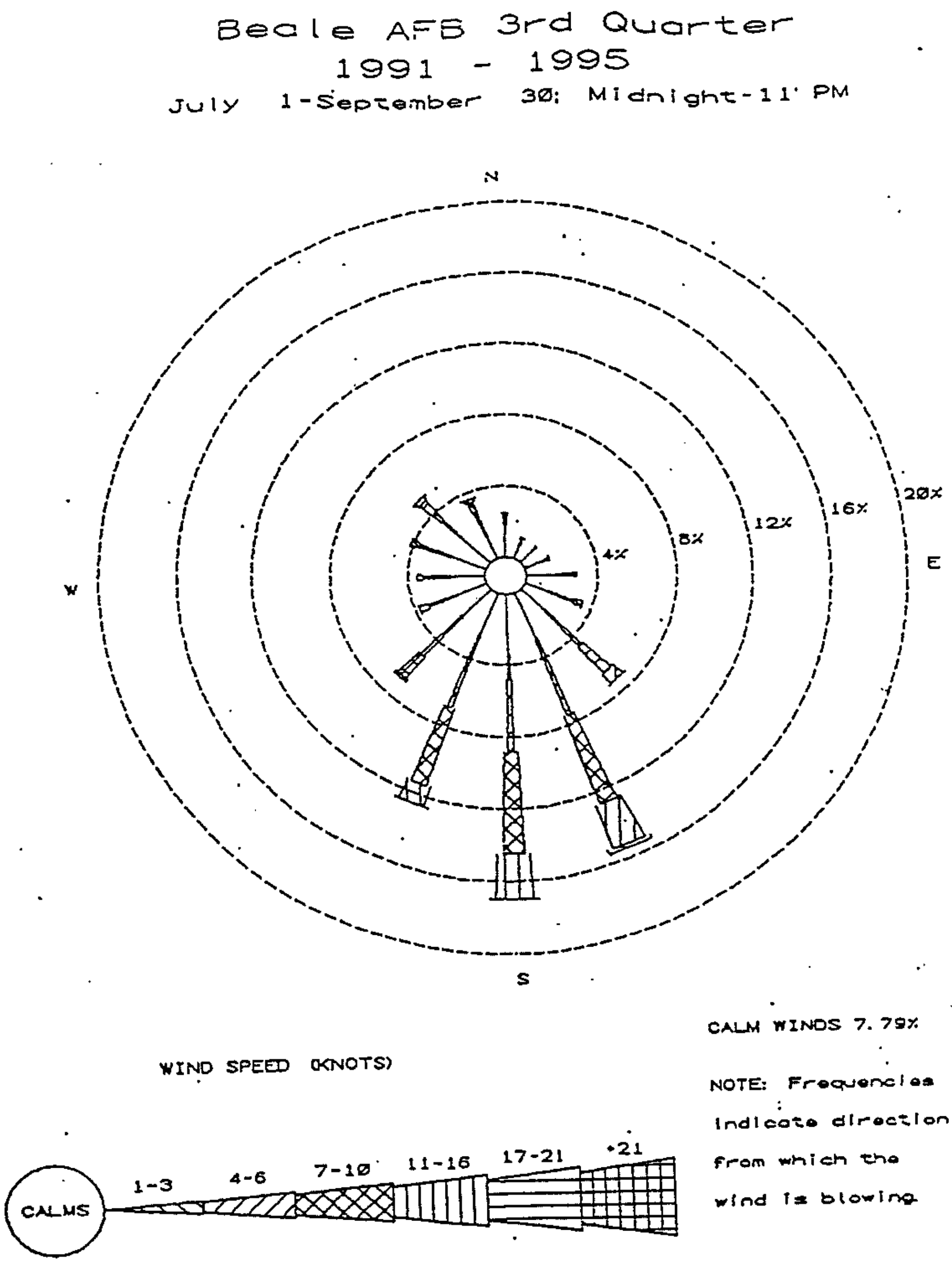
AIR QUALITY Figure 2
Windrose Q1



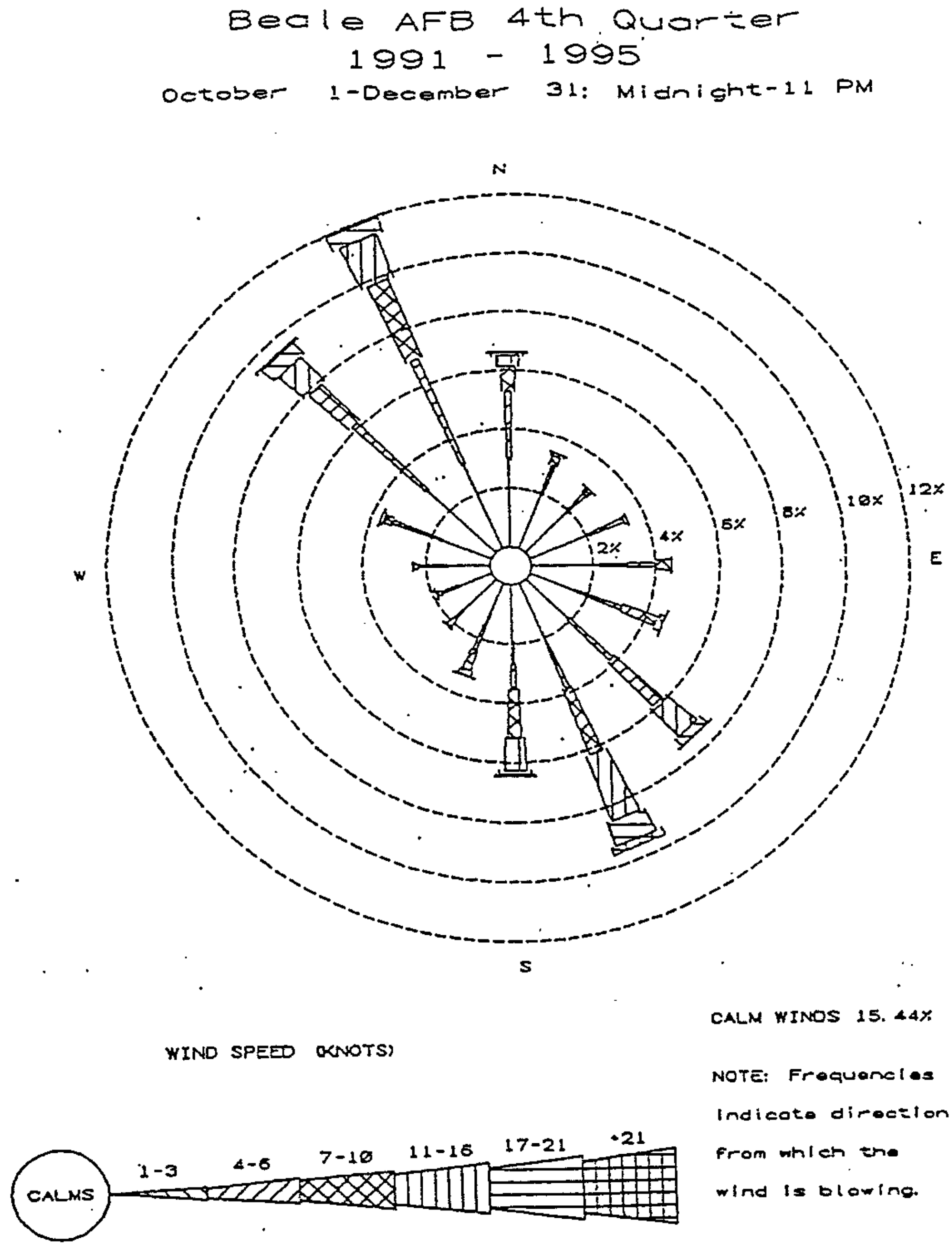
AIR QUALITY Figure 3
Windrose Q2



AIR QUALITY Figure 4
Windrose Q3



AIR QUALITY Figure 5
Windrose Q4



reported (as reported by Calpine in December 1997 submittal) from the closest meteorological monitoring station at Beale Air Force Base which is located 15 miles east of the project.

EXISTING AMBIENT AIR QUALITY

Ambient air quality monitoring data collected in the Sutter area between 1993 and 1996 are shown in AIR QUALITY Table 2. Staff evaluated the data collected from the Sutter County air monitoring stations, which are located at Sutter Buttes, Yuba City and Pleasant Grove. As can be seen in AIR QUALITY Table 2, based on the magnitude of the pollutant concentrations and the numbers of days with violations of the California Ambient Air Quality Standards (CAAQS), ozone and PM10 are the air pollutants of the greatest concern in the Sutter County area. The highest one hour ozone concentrations exceed the CAAQS during all four years. The highest twenty four hour concentrations for PM10 also exceeds the CAAQS during all four years. But the highest annual pollutant concentrations in 1995 and 1996 are below the CAAQS standards. The data also show no violations of the one hour or the 8-hour state and federal CO standards. No violations of the one hour or the annual concentrations of the NO2 CAAQS and National Ambient Air Quality standards (NAAQS). There was no data available for SO2 from the Sutter County air monitoring stations. All PM10, NO2 and CO data presented in AIR QUALITY Table 2 were collected at the Yuba City monitoring station.

AIR QUALITY Tables 3 and 4 provide a summary of the PM10 and ozone ambient air quality monitoring data collected between 1991 and 1996 from air monitoring stations located in Sutter County and Colusa County. It is clear from Table 3 that the number of days in violation of the state 24-hour average concentration of PM10 standard varies from 1991 through 1996. However, there is no clear trend or indication that PM10 air quality is improving, but the data suggest that most of the violations occur during the fall season. However, the data collected in the Sutter County area are limited to the two air monitoring stations located in Yuba City and Colusa. AIR QUALITY Table 4 presents the highest one hour average ozone concentrations, number of days of violations of the state ozone standard and the months in which the violations occurred. It is clear that the state ozone standard is violated mostly during the summer months.

AIR QUALITY Table 2
Sutter Area Ambient Air Quality Monitoring Data

Pollutant		1996	1995	1994	1993	Most restrictive Ambient Air Quality Standard
Ozone	Highest 1-hr concen. (ppm)	0.12[S]	0.13[P]	0.12[S]	0.14[P]	0.09 (CAAQS)[E]
	# of days with violations of CAAQS	22	16	23	4	---
PM10	Highest 24-hr concentrations ($\mu g/m^3$)	82[Y]	128[Y]	154[Y]	78[Y]	50 (CAAQS)
	# of days with violations of CAAQS	5	16	7	11	---
	Highest annual concentrations ($\mu g/m^3$)	25.5	29.5	31.1	32.3	30 (CAAQS)
NO_2	Highest 1-hr concen.(ppm)	.07[Y]	0.07[Y]	0.08[Y]	0.09[Y]	0.25 (CAAQS)
	Highest annual concen.(ppm)	0.013	0.014	0.016	0.017	0.053 (NAAQS)[F]
CO	Highest 1-hr concen.(ppm)	8.0[Y]	8[Y]	9[Y]	10[Y]	20.0 (CAAQS)
	Highest 8-hr concen.(ppm)	4.9	4.8	6.3	7.3	9.0 (CAAQS)
SO_2	Highest 1-hr concen.(ppm)	NA	NA	NA	NA	0.25 (CAAQS)
	Highest 24-hr concen.(ppm)	NA	NA	NA	NA	0.05 (CAAQS)
	Annual Avg. (ppm)	NA	NA	NA	NA	0.003

Y Ambient data collected at Yuba City monitoring station.
S Ambient data collected at Sutter Buttes monitoring station.
P Ambient data collected at Pleasant Grove monitoring station.
F National Ambient Air Quality Standard.
E California Ambient Air Quality Standard.

Source: CARB. 1988-1991 "California Air Quality Data".

AIR QUALITY Table 3
PM10 Air Quality Summary 1991-1996
Maximum 24-hour Average Concentration (µg/m3)

Year	Yuba City - Almond St				Colusa - 100 Sunrise			
	Highest 24-hour Average (µg/m3)	Days above state std.	% of Annual Violations †	Months violations occurred	Highest 24-hour Average (µg/m3)	Days above state std.	% of Annual Violations †	Months violations occurred
1991	108	22	32%	J, O, N, D	102	19	31%	J, O, N, D
1992	79	13	18%	J, Au, S, O, N	84	8	11%	Au, S, O
1993	78	11	15%	S, O, N	70	4	6%	S, N
1994	154	7	11%	J, Au, S, O	57	5	8%	S, O
1995	128	16	24%	F, O, N	93	18	25%	S, O, N
1996	82	5	8%	J *	57	3	5%	My *
California Ambient Air Quality Standard: 50 µg/m³ (24-hour average) National Ambient Air Quality Standard: 150 µg/m³ (24-hour average)								

Source: CARB. 1991-1996 "California Air Quality Data".

† The percent of annual violations is the number of days above the CAAQS compared to the total number of measurements annually. Measurements usually occur every sixth day.

* The reported data for 1996 is limited to the months of January to June.

Month abbreviations: J-January, F-February, M-March, Ap-April, My-May, Ju-June, Jl-July, Au-August, S-September, O-October, N-November, D-December

AIR QUALITY Table 4
Ozone Air Quality Summary, 1991-1996

Year	Pleasant Grove			Sutter Buttes			Yuba City - Almond ST		
	Highest 1-hr. Avg. (ppm)	Days above state std.	Months violations occurred	Highest 1-hr. Avg. (ppm)	Days above state std.	Months violations occurred	Highest 1-hr. Avg. (ppm)	Days above state std.	Months violations occurred
1991	0.10	7	Jl, S, O	NA*	NA*	NA*	0.11	5	F, Jl, S, O
1992	0.12	12	My, Ju, Jl, Au, S	NA*	NA*	NA*	0.12	23	My, Ju, Jl, Au, S, O
1993	0.14	4	My, Ju, Au	0.12	11	Jl, Au, S, O	0.10	1	Jl
1994	0.10	1	Au	0.12	23	My, Ju, Jl, Au, S, O	0.11	12	Jl, Au, S, O
1995	0.13	11	Jn, Jl, Au, S	0.11	16	Ju, Jl, Au, S, O	0.11	8	Jl, Au, S
1996	0.10	7	Ju, Jl, Au	0.12	22	Ju, Jl, Au, S, O	0.11	11	Ju, Jl, Au, S, O
California Ambient Air Quality Standard: 0.09 ppm (1-hour average) National Ambient Air Quality Standard: 0.12 ppm (1-hour average)									

Source: CARB. 1991-1996 "California Air Quality Data".*
Data are Not Available (NA).

Month abbreviations: J-January, F-February, M-March, Ap-April, My-May, Ju-June, Jl-July, Au-August, S-September, O-October, N-November, D-December

ATTAINMENT STATUS

Sutter County is divided into north and south air quality regions with a dividing line at Subaco Road, approximately 7.1 miles south of the SPP site. For air quality planning purposes and based on the populations in the area, the U.S. EPA established that the southern portion of Sutter County is part of the Sacramento Air Quality Maintenance Area (SAQMA). The attainment status of Sutter County for different air pollutants is presented in AIR QUALITY Table 5.

AIR QUALITY Table 5
Attainment Status Of Sutter County

Pollutant	Federal Attainment Status	California Attainment Status
NOx	Attainment/Unclassified	Attainment/Unclassified
CO	Attainment/Unclassified	Attainment/Unclassified
SO2	Attainment/Unclassified	Attainment/Unclassified
Ozone-Northern Portion	No Status	Nonattainment
Ozone-Southern Portion	Serious Nonattainment	Serious Nonattainment
PM10	Attainment	Moderate Nonattainment
Lead	Attainment/Unclassified	Attainment/Unclassified

Source: Calpine (Calpine Corporation). 1997. Page 8.1-12.

PROJECT DESCRIPTION

This section describes the project design and criteria pollutant control devices as presented in the SPP's application and subsequent data responses filed since December 1997.

PROPOSED EQUIPMENT

The major equipment proposed in the SPP application includes the following:

- Two Westinghouse 501FC combustion turbine generators with a gross capacity of 170 MW of electricity each;
- One steam turbine generator with a gross capacity of 160 MW;

- Two heat recovery steam generators (HRSG) with a capacity of 463,769 lb/hr of high pressure steam;

- Two duct burners, each with a firing capacity of 170 MMBtu/hr high heating value (HHV);

- Dry cooling tower;

- Continuous emission monitoring system (CEMS) for NOx, oxygen (O2) or CO2 and exhaust flow rate;

- Emission control systems include:
    - dry low-NOx combustors;
    - selective catalytic reduction (SCR) to control NOx;
    - oxidation catalyst to control CO and VOC.

COMBINED CYCLE FACILITY OPERATION

Calpine is proposing to construct and operate a combined cycle facility using two combustion turbines, which will each exhaust into a HRSG. Each HRSG is also equipped with supplemental duct firing to be used to produce steam for the steam turbine. It is expected that each duct burner would operate 5,460 hours/year.

The inlet air will flow through the inlet air filter/evaporative coolers and air inlet ductwork of the CTGs. It will be compressed to increase its pressure, then flow to the combustion section of the turbine. Natural gas fuel will be injected at the appropriate pressure into the combustion section and ignited. The hot combustion gases will expand though the turbine section of the CTGs, causing the turbine blades to rotate and drive the electrical generators and compression sections. The hot combustion gases will exit the turbine sections into the HRSG where water will be heated. The water will be converted to superheated steam and delivered to the steam turbine. The steam turbine will drive the electrical generator to produce additional electrical capacity. The steam will exit the low pressure side of the steam turbine and pass through a surface condenser, which will give up heat to cooling water that will be condensed to a liquid.

The cooling water will cycle through a dry cooling tower where the heat will be rejected to the atmosphere. The project is expected to have an availability factor of over 90 percent. The CTGs will produce, each, approximately 170 MW of electrical power at an average ambient temperature of 61°F.

The primary fuel used in the CTGs and the duct burner is pipeline quality natural gas. No other back-up fuel will be used in the project. The SPP project will require a new gas pipeline with two dehydrator units. These dehydrator units will remove water and condensable hydrocarbons from the natural gas. Glycol solution will be used in the condensation process to cool the natural gas. A natural gas boiler will be used to regenerate the glycol solution by heating it to approximately 375 °F. These boilers are rated at a maximum heat input of 1,000,000 Btu per hour (HHV).

Air Pollution Control Equipment

The CTGs will employ dry low NOx combustors and good combustion design to control CO and NOx emissions. NOx emissions from the combustion turbines into the HRSGs will be controlled to 25 ppm. It will be controlled further by a SCR unit located in the HRSG which will reduce the NO_x level to 2.5 ppm (15 percent O_2), averaged over one hour, as measured at the stack. The SCR unit will use anhydrous ammonia. The ammonia slip (ammonia emissions in the exhaust) will be limited to 10 ppm measured at the stack.

Particulate emissions from the CTGs will be controlled by inlet air filtration, the use of filtered natural gas as the sole source of fuel, and the use of dry low NO_x combustion turbine burner technology.

The CTGs (Westinghouse) are designed to minimize the formation of CO and ROG. It is estimated that CO and ROG concentrations at a base load operating level will be as low as 4 ppm and 1 ppm (15 percent O_2), respectively. Calpine is proposing to install a CO/ROG oxidation catalyst to guarantee achieving these levels.

Continuous emission monitors (CEMs) are proposed to be installed on the exhaust stacks for NO_x and oxygen, to assure adherence to the proposed emission limits. The CEMs will be installed, calibrated, operated and maintained in accordance with District procedures and applicable EPA Performance Specifications 2, 3, and 4 of Title 40, Code of Federal Regulations, Part 60, Appendix B.

ESTIMATED PROJECT EMISSIONS

SPP Project's Construction Activities and Associated Air Emissions

During the project construction period, air emissions will be generated from the exhaust of heavy construction equipment, such as water trucks, rollers, excavators, graders, tractors, air compressors, forklifts, dozers, and scrapers; fugitive dust will be generated from activities such as cleaning, grading, and preparation of the site; and from the construction of the transmission lines and gas line.

The estimated air pollutant emissions in the tables below are based on the assumption that all equipment is operating concurrently and maintained and operated properly. The air emissions associated with the construction of these facilities are summarized in AIR QUALITY Tables 6 and 6A. AIR QUALITY Table 6 summarizes the daily air emissions associated with each construction phase of the project, including the linear facilities.

The construction of the proposed natural gas line, drip stations, natural gas dehydrators, switchyard and transmission lines will generate short-term air emissions in the form of fugitive dust and vehicle emissions. The pipeline route requires a total of 13 miles of trenching for a 16-inch diameter pipe. The trench is expected to be 2.5 to 3 feet wide and 6 to 7 feet deep. The natural gas line requires two new dehydrator units, one to be located at the Sacramento Drip Station in Sutter County, and the other at Poundstone Drip Station in Colusa County. Both drip stations will be permitted, owned and operated by PG&E. The air emissions associated with the dehydrators are generated from the condensation tank, which will vent VOC emissions, and from operation of the boilers which will burn natural gas at 1,000,000 Btu per hour. The boilers will operate 8,760 hours per year. The air emissions associated with the dehydrators, boilers and fugitive VOC emissions from the valves and flanges are summarized in AIR QUALITY Table 7.

The electrical transmission line will require the installation of approximately 32-38 poles. Each pole will be supported by a 3.5 feet in diameter and 12 feet deep hole for concrete foundation. In addition, the switchyard site will be excavated to a depth of two feet to allow for the installation of the ground grid and conduits. A summary of the air emissions associated with the construction activities for the gas pipe line, switchyard and transmission lines is shown in AIR QUALITY Table 7A.

AIR QUALITY Table 6
Estimated SPP Construction Emissions (lb/Day)

NOx	SO_x	PM_{10}	CO	ROG
Phase I - Site Preparation Emissions				
315	27.7	343	153	37.5
Phase II - Construction Emissions				
163.5	14.1	19.3	77.2	19.8
Construction Worker Vehicle Emissions				
19.5	0	7.7	106	12.1
Natural Gas Line Construction Emissions				
40	4	37	28	5
Electrical Transmission Lines Construction Emissions				
57.9	4.2	7.2	26.3	6.8
Site Elevation Emission Estimates (Equipment & Fugitive Dust)				
154	18	1941(1)	178	23
Switchyard Construction Emissions				
57.5	5	11	35.1	9.3
1. This value includes 550 lb/day from equipment PM10 emissions and 1,391 lb/day from fugitive dust.				

Sources: Calpine (Calpine Corporation). 1997 page 8.1-25 through 8.1-31) and Calpine (Calpine Corporation). 1998j. Response to data requests 64 and 66 with additions to 63, 67 and 68.

AIR QUALITY Table 6A
Estimated SPP Construction Emissions (lb/Project)

Equipment Type	NOx	SOx	PM10	CO	ROG
Heavy-duty Construction Equip. Phase I[4]	6,659	616	819	3,188	886
Light-duty Trucks[4]	6,517	592	764	3,371	853
Worker Vehicles[1]	4,200	[2]	1,600	23,400	2,600
Delivery Vehicles[4]	1,235	82	141	534	141
Wheeled Tractors[4]	570	48	59	384	81
Track type loaders[4]	1,635	137	204	762	136
Fugitive Dust from Excavation & Delivery[3]			9,216		
Total Emissions (lbs)	**20,815**	**1,476**	**12,804**	**31,640**	**4,697**
SPP Construction Emissions (tons)	**10.4**	**0.74**	**6.4**	**15.82**	**2.35**

1. Assumes that: a) vehicles are 1990 models, 250 workers, 208 vehicle, 80 miles round trip, avg. speed 45 mi/hr., 1.2 worker/vehicle and 2 cold start-up/vehicle/day.
2. Anticipated to be negligible based on the fuel sulfur content and engine efficiency.
3. Based on: AP-42 section 13.2.3.3., 64 percent of the TSP emissions is PM10.
4. Based on: a) emission factors from EPA 1991, b) all particulate matter assumed to be PM10.

Source: Calpine (Calpine Corporation). 1997. Pages 8.1-27-30.

AIR QUALITY Table 7
Drip Stations Natural Gas Dehydrators Emissions*

Pollutant	lb/hour	lb/day	Ton/Year
NOx	0.2	4.8	0.86
CO	0.042	1.0	0.18
VOC	0.012	0.28	0.06
SO2	0.0012	0.028	0.006
PM10	0.024	0.56	0.1

* Natural gas dehydrator units construction emissions include Sacramento and Poundstone Drip Stations. Emissions estimates are based on the revised (oct. 1996) U.S. EPA AP-42 emission factors, section 1.4.

Source: Calpine (Calpine Corporation). 1997. Page 8.1-25.

AIR QUALITY Table 7A
Estimated Linear Facilities Construction Emissions

	NOx	SOx	PM10[1]	CO	ROG
Natural Gas Line	4,247	385	3,925	2,932	526
Electrical Transmission Lines	3,400	280	280	1,440	280
Switchyard	5,800	400	1,200	3,600	1,000
Site Elevation (equipment)	5,529	654	550	6,392	810
Site Elevation (Fugitive Dust)		0	49,891		
Total Emissions (lbs/Project)	18,976	1,719	55,846	14,364	2,616
Total Emissions (tons/Project)	**9.5**	**0.86**	**28**	**7.2**	**1.3**

1. Includes both vehicle exhaust and fugitive dust.

Source: Calpine (Calpine Corporation). 1997. Pages 8.1-30-32.

Potential Criteria Pollutants Generated from the Operation of SPP Project

Air emissions will be generated from the dehydrators and the major components of the SPP project. Calpine assumes that each dehydrator unit includes 100 glove valves and 100 flat gasket flanges. By using the American Petroleum Institute (1980) emission factors of 0.471 lbs/day for the valves and 0.267 lbs/day for the flanges, the total hydrocarbon emissions are 26,937 lbs/year. The Applicant assumes that natural gas is approximately 95.21 percent by volume methane and carbon dioxide and 4.79 percent by volume VOCs. By using these assumptions, the maximum annual fugitive VOC emissions for all valves and flanges is 0.65 ton per year.

Air pollutant emissions will also be generated from operating the major project components. The SPP will utilize two combustion turbines. Calpine examined more than one turbine type and chose the Westinghouse 501FC turbine for the SPP project. Staff evaluated the air emissions associated with the turbine based on manufacturer hourly guaranteed emission factors.

The proposed operating assumptions are:

a) operating each turbine for 19 hours per day with a maximum 8,110 hours per year;

b) operating each duct burner for 22 hours per day with a maximum 5,460 hours per year;

c) two start-ups per day for each turbine, one hot start-up for one hour and one cold start-up of 3 hours (only two hours of uncontrolled emissions); cold start-up is when the turbine has not been in operation for 72 hours or longer;

d) two one-hour shut-downs per day for each turbine;

e) 50 cold start-ups and 250 hot start-ups per each turbine on an annual basis;

f) operating the dry cooling tower, no PM10 emissions;

g) steam injection for power augmentation is based on 19 hours per day, with a maximum of 2,000 hours per year.

Westinghouse Turbine

AIR QUALITY Table 8 shows the hourly air emission levels as calculated by Calpine and guaranteed by the manufacturer for the major components of the project.

AIR QUALITY Table 8
Maximum Hourly Emissions (lb/hour) Using Westinghouse Turbine

Pollutant	CTG(2)	Duct Burner(3)	Steam Injection	Hot Start-up	Cold Start-up(4)	Shutdown
NOx	16.8	1.4	0.9	170	175	26.6
CO	16.7	3.4	14.2	902	838	98.2
VOC	1.5	2.0	0.01	7.2	7.2	7.2
SO2	3.7	0.005	0.31	2.3	2.3	2.3
PM10	9.0	2.5	0.0	6.7	6.7	6.7

(1) No emissions associated with cooling towers.
(2) All air emissions are calculated based on CTG operation at 20F and 100 percent load rate.
(3) Duct burner emissions are calculated based on firing 170 MMBtu/Hr (HHV) of natural gas.
(4) Cold start-up emission levels represent one hour.

Sources: Calpine (Calpine Corporation). September 22,1998. Cooling Tower Information.
Calpine (Calpine Corporation). 1998j. Response to data requests 64 and 66 with additions to 63, 67 and 68.

AIR QUALITY Table 9 presents the maximum daily emission levels as estimated by Calpine using the assumptions presented above. The air emission levels assume maximum hourly operation of the project per day. Calpine estimates that uncontrolled air emissions associated with cold start-ups are based on 2 hours, which staff believes is sufficient time for the SCR to warm-up and control the NOx emissions consistent with manufacture guarantees.

AIR QUALITY Table 9
Maximum Daily Emissions (lb/day) Using Westinghouse Turbine

	CTG	Duct Burner	Steam Injection	Hot Start-up	Cold Start-up(1)	Shutdown	Total Emission Per CTG	Calpine(2) Maximum Project Daily Emissions
Hrs./Day	19	22	19	1	2	2	24	24
NOx	318.3	29.9	17.5	170	349	24	909	1817
CO	317.3	74.8	269.5	902	1,675	25	3264	6528
VOC	28.5	44.9	0.2	1.1	2	2.2	79	158
SO2	70.3	0.12	5.9	2.7	5	5.3	90	179
PM10	171.0	54.6	-	9.0	18	18	271	541

(1) Cold start-ups are based on 1.5 of uncontrolled emissions to allow the SCR to warm-up, then, all the emissions will be controlled.
(2) Based on two turbines, Calpine (Calpine Corporation). 1998j. Response to data requests 64 and 66 with additions to 63, 67 and 68. Submitted to the California Energy Commission, May 6, 1998, Sept.22, 1998.

Source: California Energy Commission Staff assumptions and calculations of daily emissions.

AIR QUALITY Table 10 presents the maximum annual emissions, as estimated by Calpine using the above assumptions. The air emission levels assume maximum hourly operation of the project per year.

AIR QUALITY Table 10
Annual Emissions Using Westinghouse Turbine (Tons/Year)

	CTG	Duct Burner	Steam Injection	Hot Start-up	Cold Start-up(1)	Shutdown	Total Emission Per CTG	Calpine(2) Annual SPP Emissions
Hrs/Yr.	8,110	5,460	2,000	250	100	300		
NOx	65.9	3.7	0.9	21.2	8.7	1.8	102	205.86
CO	61.6	9.3	14.2	113	41.9	1.9	242	483.18
VOC	5.9	5.6	0.01	0.1	0.1	0.2	11.9	24.41
SO2	14.6	0.01	0.3	0.3	0.1	0.4	15.7	31.5
PM10	36.5	6.8	0.0	1.1	0.5	1.4	46.2	92.5

(1) Cold start-up emissions are based on 50 annual start-ups, each for 2 hours.

(2) Calpine (Calpine Corporation). 1998(j). Response to data requests 64 and 66 with additions to 63, 67 and 68. These emission levels include Dehydrators, valves and flanges emissions.

Source: California Energy Commission Staff assumptions and calculations of annual emissions.

PROJECT INCREMENTAL IMPACTS

This section discusses the project's direct impacts and cumulative impacts, as estimated by Calpine and evaluated by the CEC staff.

DIRECT IMPACTS

The project's principle air pollutant emissions will be generated during the construction of the project and during the operation of the gas turbines and the duct burners. Several operating scenarios were evaluated and the worst case scenario was chosen to be modeled to estimate the project's ambient air quality impacts. The U.S. EPA approved SCREEN model was used first to evaluate the project's ambient air quality impacts. If the impacts were significant and violated the ambient air quality standards, considering the ambient background, a more refined modeling of the worst case scenario was conducted to evaluate and quantify the project ambient air quality impacts. For that purpose, the U.S. EPA recommends the use of the Industrial Source Complex (ISC) model, with either short-term (ST) or long term (LT) option. Short-term refers to impact predictions of 1 to 24 hours, whereas long-term refers to monthly, seasonal and annual averaging periods. The ISC model is a steady-state

Gaussian plume model, appropriate for regulatory use to assess pollution concentrations from a wide variety of sources associated with an industrial source complex.

Five years of hourly meteorological data collected at the Sacramento Metro Airport National Weather Service (NWS) station monitor (1985 through 1989) were used in the modeling analysis. Concurrent mixing height data from the Oakland Airport, as well as different meteorological conditions, such as stability classifications and various wind speeds, were also used in the modeling analysis.

Construction Impacts

The SPP construction activities will be completed in two phases. Phase I will include the site preparation, phase II will be limited to the construction of the project. The air quality impacts of construction and site preparation are summarized in AIR QUALITY Table 14 below. The linear facilities impacts are insignificant because they require minimal equipment and occur along roads covering a large geographical area. The impacts from the construction equipment are anticipated to be of short duration and unavoidable, because of the sporadic nature of the construction phase of the project.

As AIR QUALITY Table 14 also shows that the estimated PM10 and NO2 impacts from the project incombination with ambient pollutant levels, exceed air quality standards. The ISC model was used to evaluate the maximum impact levels. However, for SO2 and CO, the SCREEN model was used to quantify the emission impacts.

AIR QUALITY Table 14
Summary of the SPP Construction Activities Impacts
On Ambient Air Quality

Pollutant	Averaging Period	Max. Impacts (µg/m3)	Background	AAQS Standard (µg/m3)
SO2	3 hours	138.7	26.1	1,300 NAAQS
	24 hours	61.6	7.83	105 CAAQS
	annual	15.4	0.0	80
CO	1 hour	840.6	11.4	23,000 CAAQS
	8 hours	488.4	8.3	10,000 CAAQS
NO2	1 hour	170.9	150.4	470 CAAQS
	annual	90.4	31.97	100 NAAQS
PM10	24 hours	699.3	154	50 CAAQS
	annual	14.4	36/7	30 CAAQS
(1) Calpine used ISC model to evaluate NOx and PM10 emissions impacts, and used SCREEN model to evaluate the SO2 and CO impacts.				

Source: Calpine (Calpine Corporation). 1997. Page 8.1-35.

OPERATING IMPACTS

The modeling analysis of the operation of the combined cycle facility indicated that the worst case emission scenario resulted from operating the CTG during cold start-up for one hour and the duct burner at 100 percent load. The SCREEN model was used initially to evaluate the NO2, CO and SO2 emissions impacts. More refined modeling was needed to accurately evaluate the impacts. The ISC model was used for the refined analysis. AIR QUALITY Table 15 summarizes the ISC modeling results. The impacts from the project added to the ambient background were much lower than the most stringent standards for these pollutants, as shown in AIR QUALITY Table 15.

In evaluating PM10 impacts from the project, Calpine included the two CTGs, duct burners, and steam injection emissions. Since the project's PM10 impacts will likely contribute to existing violations of the state 24 hour standard, the ISC model was used to refine the analysis and better evaluate the PM10 impacts. The project impacts were added to the ambient background and calculated as a percent of the National or California standards. As shown in AIR QUALITY Table 15, project emissions will violate both the 24 hour and annual PM10 standards.

Given the complexities of secondary pollutant formation in the atmosphere, staff did not model the ozone or the secondary PM10 impacts of the project. Staff, nevertheless, assumes that emissions of ozone precursors, such as NOx and VOC, in areas of ozone non-attainment, may contribute significantly to ongoing violations within the District and therefore cause an adverse air quality impact. Staff considered the significance of such contributions in the context of historical air quality trends, current ambient air quality conditions and expected future air quality conditions, as described in the District's air quality management plan. Staff also assumes that the project's NOx emissions may be converted to nitrates and potentially contribute to existing PM10 violations. As with ozone, staff evaluates the significance of such contributions in the context of current and expected future PM10 air quality trends. As shown in AIR QUALITY Table 5, the District is currently classified nonattainment for both the state ozone and PM10 standards. Therefore, staff believes that the project's contributions of NOx and VOC emissions to ozone and secondary PM10 formation are potentially significant and should be mitigated.

AIR QUALITY Table 15
SPP Nonreactive Pollutant
Ambient Air Quality ISC Modeling Results

Pollutant	Averaging Period	Project Impact (µg/m3)	Background (µg/m3)	Total Impact (µg/m3)	Limiting Standard (µg/m3)	Type of Standard	Percent of Standard (%)
NO_2[1]	1-hour	241.2	150.4	391.6	470	CAAQS	83
	Annual	0.26	31.96	32.2	100	NAAQS	32
PM10[1]	24-hours	0.55	154	154.55	50	CAAQS	309
	Annual	0.097	36.7	36.8	30	CAAQS	123
PM2.5[1]	24-hours	0.55	154	154.55	50	CAAQS	238
	Annual	0.097	36.7	36.8	30	CAAQS	245
CO[1]	1-hour	1243	11.4	1254	23,000	CAAQS	6
	8-hours	305.2	8.3	314	10,000	CAAQS	3
SO_2	3-hours	1.3	26.1	27.4	1,300	NAAQS	2
	24-hours	0.6	7.83	7.89	365	NAAQS	8
	Annual	0.1	0.0[3]	0.1	80	NAAQS	0.1

1. The project emissions include emissions during start-up.
2. Background data is based on Yuba City monitoring station.
3. No representative ambient data available within the region.

Source: Calpine (Calpine Corporation). 1997. Pages 8.1-33-35, November 2,1998.

CUMULATIVE IMPACT ANALYSIS

The Energy Commission staff provided Calpine with a modeling protocol to conduct the cumulative impact analysis. The major component of the protocol required Calpine to include in the modeling all known future projects within six miles of the SPP. Then, the modeling results (impacts) would be added to the ambient background levels to establish the total impact. The District conducted a comprehensive review and determined that there are no planned facilities within the six miles that are eligible for modeling. Therefore, the cumulative impact analysis was unnecessary.

The cumulative impacts of the linear facilities reviewed by the Sutter Community Services Department identified that Hughes Road - East Sutter Bypass Canal Bridge replacement is a proposed project within the County. This project is adjacent to the natural gas pipeline route. The project construction will be completed by October 15, 1998. The natural gas line construction is planned for the summer of 2000. Since the Hughes Road - East Sutter Bypass Canal Bridge replacement project will be completed prior to the start of construction of natural gas line, a cumulative impact analysis was not necessary.

COMPLIANCE WITH LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

Calpine has submitted an application for a PSD permit to the EPA Region IX Office. At the time of preparation of this analysis, the PSD application has been deemed complete. Staff will maintain contact with the EPA staff to track the status of the permit review and any project issues identified.

STATE

Based on our assessment of the project's impacts, staff believes that the project complies with section 41700 of the California State Health and Safety Code.

LOCAL

The District has issued their Final Determination Of Compliance (FDOC) on November 10, 1998. Based on a review of the FDOC,staff has determined that the project will comply with applicable District rules and regulations subject to the completion of the memorandum of understanding (MOU) between the District and Sacramento Metropolitan Air Quality Management District (SMAQMD), and approval of the paving the road contract between Calpine and the Sutter County.

MITIGATION

In this section we evaluate the measures that Calpine is proposing to mitigate the project's air pollutant emissions impacts from the construction of the combined cycle facility and the transmission line, and from operation of the power plant.

CONSTRUCTION MITIGATION

Project construction activities will occur over a two-year period. The fugitive dust emissions from the construction of the project, switchyard and transmission line will be controlled by periodic watering of the site, assuming a 50 percent effectiveness, along with the following mitigation measures proposed by Calpine:

1. Areas of excavated or disturbed soils where construction activities have ceased for more than 15 days will be covered, or treat with a dust suppressant compound (such as magnesium chloride).

2. The beds of trucks will be covered when hauling excavated soils which have the potential to generate fugitive dust.

3. The construction area and scheduled activities will be limited to minimize disturbance.

4. Before trucks leave the site, their tires will be rinsed so they will not track soil off-site.

5. A maximum speed limit of 15 miles per hour will be posted on site.

6. Construction activities will be discontinued when wind speeds are greater than 20 mph.

The emissions from the construction equipment listed in AIR QUALITY Tables 6 and 7 will be minimized through the proper maintenance of the construction equipment to meet the applicable equipment emission standards.

OPERATION MITIGATION

The project's air pollutant emission impacts will be mitigated through a combination of the use of natural gas as the sole fuel, the use of air pollution control equipment and the provision of offsets. Calpine proposes to use a CTG with dry-low NO_x combustors, combined with an SCR system which uses ammonia injection to further reduce the NOx missions.

Calpine proposes to use a CO oxidation catalyst to reduce CO emissions to 4 ppm (15 percent O_2). Air pollutant emission levels will be properly monitored through the use of a continuous emission monitoring system.

<u>Control of NOx Emissions</u>

The project's NO_x emissions consist primarily of nitric oxide (NO) and a small percentage of nitrogen dioxide (NO2). Thermal NOx is the product of the oxidation of NO2 (present in the air used for combustion) at the temperatures present in the combustion process. Some NOx is formed from the oxidation of nitrogen present in the fuel. Nitrogen is not present in significant quantities in natural gas, so most of the NOx emissions from this project are due to thermal NOx.

Combustion chamber NO_x can be controlled by reducing the flame temperature in the combustion chamber through quenching steam and dilution using water and steam injection. Additionally, thermal NOx can be controlled with combustor designs that premix the air and fuel and stage the combustion process (a reducing atmosphere followed by an oxidizing atmosphere).

NOx emissions from the generation facility will be controlled through the use of dry low NOx combustors in the CTGs and the use of SCR as a post-combustion emission control. The turbines will be equipped with a number of dry low-NOx combustors to ensure optimal uniform temperature distribution in the primary air zone. A reduction in NOx emissions is also achieved by raising the mean air/fuel ratio. The dry-low NOx burner produces emissions as low as 25 ppm when natural gas is burned before entering the SCR.

Calpine's proposed SCR system will control NOx emission levels to 2.5 ppm corrected @ 15 percent O_2. SCR is a process that chemically reduces NOx with ammonia (NH_3) over a catalyst in the presence of oxygen (O_2). The process is termed selective because the NH_3 reducing agent preferentially reacts with NOx rather than O_2 to form N_2 in the presence of excess O_2 at temperatures in the range of 400 to 750 °F. If the temperature is lower than 400°F, the ammonia reaction rate is low, and therefore, NH_3 emissions (called ammonia slip) will increase.

<u>**SCONOx Technology as An Alternative Mitigation**</u>

The SCONOx system uses a catalyst bed which is located inside the HRSG anywhere within a 260 °F to 700 °F temperature range. As hot exhaust gases pass through the catalyst rack, the NOx molecules are adsorbed onto the catalyst surface. When the catalyst is regenerated using a regeneration gas containing 4 percent hydrogen, 3 percent nitrogen, and 1.5 percent carbon dioxide. The regeneration gas is created by reacting natural gas with air in the presence of an electrically heated nickel oxidation catalyst, which is electrically heated to 1900 °F. The gas is then mixed with steam (produced from the HRSG) and passes over a second catalyst to form the regeneration gas. The regeneration gas is introduced into the catalyst rack through a system of piping and louvers. The regeneration gas exits the catalyst rack is ducted back into the HRSG, upstream of the SCONOx.

SCONOX has been evaluated by USEPA Region IX, and they have acknowledged that a 2 ppm @ 15% O_2 NOx control level can be achieved in practice using the technology. Furthermore, USEPA recommended that new sources subject to the BACT requirements in Part C of the CAA should consider the 2.0 ppmv @15% O_2 for three hours avenging time or 2.5 ppmvd @15% O_2 for one hour avenging time as an achievable emissions limit in their BACT analyses.

Control of Carbon Monoxide (CO) and Reactive Organic Gases (ROG)

Combustion turbines inherently generate low CO and ROG emissions. High combustion temperatures, fuel/air mixing, and the excess air inherent in the CTG's combustion process favor complete combustion of fossil fuels. These conditions, however, also lead to higher NO_x emissions. Current CTG designs attempt to balance achieving low NO_x emissions (from the CTG prior to post-combustion controls) while keeping CO and ROG emissions low. Good operating and maintenance practices will be used to limit the project's CO and ROG emissions.

Calpine proposes to install an oxidation catalyst downstream from the CTGs and the duct burners to reduce CO emissions. While the catalyst's ROG removal effectiveness is not guaranteed, the oxidation catalyst, which is a standard design, is expected to reduce ROG emissions by five percent for this project.

Control of PM10

Natural gas fuel contains only trace quantities of noncombustible material. Particulate emissions (PM_{10}) will be controlled by inlet air filtering for the combined cycle CTG and HRSG unit. In addition, Calpine proposes to use a dry cooling tower which has no PM10 emissions associated with its operation, which is the best control technology available.

Sulfur Dioxide Emissions Control

SO2 emissions result from the combustion of any sulfur-bearing fuel. The SPP SO2 emissions will be controlled by burning only natural gas, which typically contains only traces of sulfur. The emissions from the project's CTGs are expected to be very small without any additional post-combustion SO2 control equipment. Since natural gas contains only 2000 grains of sulfur per million cubic feet, the resulting SO2 emission concentrations should be less than 1.0 ppm @15% O_2.

Emission Offsets

To fully mitigate the facility's potential emission increases, Calpine plans to purchase emission reduction credits (ERCs) from District's ERCs bank and the Sacramento Metropolitan Air Quality Management District (SMAQMD) ERCs bank. Calpine has option contracts with some of these sources of ERCs and has letters of intent to purchase ERCs with others. Calpine will provide option contracts for all of the ERC sources before the Commission's makes its final decision on the project. AIR QUALITY Table 16 provides a summary of all proposed sources of ERCs, including quantities and contract types. The ERCs levels in the table are much greater than the SPP liabilities to satisfy the District rules.

AIR QUALITY Table 16
ERCs Sources Types And Location

ERC Source	Contract Type	Location	ERC Certificate No.	NOx Location Emissions (Tons)	VOC Emissions (Tons)	PM10 Emissions (Tons)
Atlantic Oil Co.	Optional Contract	FRAQMD	95-1	21.9	5.0	0
PG&E	Letter of intent	SMAQMD	0020	105	0	0
PG&E	Letter of intent	SMAQMD	287/288	132	3.8	0
Rosboro Lumber	Optional Contract	FRAQMD	94-1	41.1	20.6	28.1
Tri-Union	Letter of intent	FRAQMD	98-101	6.8	0	0
Tri-Union	Letter of intent	FRAQMD	992024	34	0.52	0
Road Paving	MOU	FRAQMD		0	0	82.8
Total ERCs under negotiation and secured with option contracts				**340.8**	**29.92**	**110.9**
Total SPP Project Liabilities				**205.86**	**24.41**	**92.5**

Source: Feather River Air Quality Management District (FRAWMD)

According to the District rules, District's staff has to prepare a memorandum of understanding (MOU) with the SMAQMD for those ERCs coming from the Sacramento District's bank. The District's staff is actively preparing the MOU and is in the process of presenting it to the Sutter District Board. Furthermore, Calpine is in the process of signing an agreement with the Sutter County to pave 5.6 miles of county roads to partially mitigate PM10 emissions from the SPP. These roads are 0.7 mile of McClatchy Road, 0.5 mile of Schlag Road, 3.5 miles of Boulton Road and 0.9 mile of Pierce Road.

Interpollutant Trading Ratios

Calpine has suggested that they may use interpollutant trading of VOC ERCs for NOx

ERCs as part of their offset strategy, which is identified and evaluated in the PDOC. Both VOCs and NOx are precursors to the formation of ozone in the atmosphere. The premise of interpollutant trading is based on "interprecursor offsets", which are limited to exchange between pollutants which are both precursors to the same secondary pollutant. However, this concept does not apply when a pollutant is a precursor to a nonattainment pollutant but would also contribute to existing violations of a state or federal standard. The District New Source Review Rule 10.1 section E.2.d., which deals with the use of interpollutant trading, reads: "...The APCO may approve the substitution of one air contaminant for another air contaminant to meet the requirement for offsetting an emission increase on a case-by-case basis, provided that the applicant demonstrates to the satisfaction of the APCO, through the use of an impact analysis, that the emission increases from the new or modified source will result in a net air quality benefit and will not cause or contribute to a violation of any air quality standard." Calpine is proposing to mitigate NOx for NOx and VOC for VOC at this time. They may choose to use interpollutant trading ratio of 2 to 1 VOC for NOx.

CONCLUSIONS AND RECOMMENDATIONS

Based upon the evidence of record, and assuming the implementation of the following Conditions of Certification, including the conditions contained in the FDOC, the Commission staff concludes that the SPP will meet all applicable air quality requirements and will not cause any significant air quality impacts.

CONDITIONS OF CERTIFICATION

AQ-1 As part of the requirements for Condition SOIL&WATER-3 for the preparation of a grading and erosion control plan for the project site, the project owner shall include and identify in that plan the following:

- the location of all paved roads, parking and laydown areas,
- the location of all roads, parking areas and laydown areas that are surfaced with gravel,
- the location of all roads, parking areas and laydown areas that are treated with magnesium chloride dust suppressant or equivalent, and
- the location of all dirt storage piles

Verification: At least 30 calendar days prior to the start of grading on the project site, the project owner shall submit for review and approval to the Commission Compliance Project Manager (CPM) in writing, and with construction drawings, a City/County of Sutter-approved erosion and sediment control plan. This plan shall include the delineation of the control measures discussed above for all roads, parking areas and laydown areas, and the location of all dirt storage piles.

AQ-2 The project owner shall perform the following mitigation measures during the construction phase of the project:

a. The areas of disturbance within the construction site shall be watered so that they are visibly wet, twice or more daily, as necessary. This condition shall not apply on rainy days when precipitation exceeds 0.1 inch.

b. Any graded areas where construction ceases shall be treated with a magnesium chloride (or equivalent) dust suppressant within fifteen days, or sooner if windy conditions create visible dust beyond the project site boundary.

c. Magnesium chloride (or equivalent) dust suppressant or fabric covers shall be applied to any dirt storage pile within three days after the pile is formed, or sooner if windy conditions create visible dust beyond the project site boundary.

d. Prior to entering public roadways, all truck tires shall be visually inspected, and, if found to be dirty, cleaned of dirt using water spraying or methods of equivalent effectiveness, subject to CPM approval.

e. At least 500 yards from construction site entrances, public roadways shall be cleaned on a weekly basis, or when there are visible dirt tracks on the public roadways, by either mechanical sweeping or water flushing.

f. A speed limit sign shall be posted at the entrance of the construction site, to limit vehicle speed to no more than 15 miles per hour on unpaved areas.

g. All construction equipment shall be properly maintained to detect and prevent mechanical problems that may cause excess emissions.

h. No construction equipment shall be kept idling when not in use for more than 30 minutes.

Verification: The project owner shall maintain a daily log of water truck activities, including the number of gallons of water used to reduce the dust at the construction sites. A log or record of the frequency of public road cleaning shall also be maintained. These logs and records shall be available for inspection by the CPM during the construction period. The project owner shall identify in the monthly construction reports, the area(s) that the project owner shall cover or treat with dust suppressants. The project owner shall make the construction site available to the District staff and the CPM for inspection and monitoring.

AQ-3 Prior to the start of construction (defined as any construction-related vegetation clearance, ground disturbance and preparation, and site excavation and soil remediation activities) , the project owner shall provide the CPM with the following information: the name, telephone number, resume, and indication of availability of the on-site Environmental Coordinator.

Protocol: The resume shall include appropriate education and/or experience in environmental management or coordination such as monitoring hazardous waste site remediation, experience as an inspector with an air pollution control district, or experience as an environmental health and safety project manager.

The CPM will review the qualifications of, and must approve in writing, the project owner's designated Environmental Coordinator prior to the start of construction.

Verification: At least 90 days prior to the start of construction, the project owner shall submit to the CPM for review and written approval the information required above.

AQ-4 The on-site Environmental Coordinator shall be on-site every work day during site preparation.

Duties: The on-site Environmental Coordinator shall inspect and ensure that all fugitive dust mitigation measures during the site preparation phase of construction are properly implemented, including, but not limited to, the mitigation measures specified in Condition AQ-2. The primary responsibility of the Environmental Coordinator is to insure that no fugitive dust emissions are seen being emitted beyond the property line under control by the project owner.

Verification: See verification for Condition AQ-5.

AQ-5 The on-site Environmental Coordinator will exercise the authority to halt any on-site activity, temporarily stop activities, or direct activities to proceed under a modification of the mitigation requirements of Condition AQ-2, if, in the opinion of the Environmental Coordinator, the project owner is not complying with the requirements of Condition AQ-2 or fugitive dust emissions are noticed beyond the project boundary.

Verification: The environmental Coordinator will prepare a daily report of the day's construction activities and appropriate fugitive dust mitigation measures employed by the project owner. A summary of the daily reports shall be included in the monthly compliance report to the CPM. If any complaints by the public are received, or if the project owner does not agree to comply with instructions given by the Environmental Coordinator, or if any other fugitive dust issue, in the judgement of the Environmental Coordinator, needs to be brought to the attention of the CPM, the Environmental Coordinator shall contact the CPM immediately.

AQ-6 For all utility trenching activities, the project owner shall implement the following control measures if necessary to prevent fugitive dust emissions:

a. To top layer of soil shall be pre-wetted prior to excavation,

b. Travel surfaces shall be wetted with the use of a water truck, and

c. All exposed soil areas shall be wetted by the use of hose spraying.

Verification: District staff and the CPM may inspect utility trenching sites at any time to monitor compliance for this condition.

AQ-7 The facility shall not discharge from any source whatsoever such quantities of air contaminants or other materials that cause a public nuisance. (District General ATC Permit Condition a)

Verification: As part of the semiannual Air Quality Reports (as required by AQ-43), the project owner shall include the date and time when any accidental release of air contaminants or other materials occur. The Air Quality Report shall also include the reason for the accidental release and measures taken to correct it.

AQ-8 The facility shall not emit particulate emissions from any single source which exceed an opacity equal to or greater than twenty percent (20%) for a period aggregating more than three (3) minutes in any one (1) hour, excluding uncombined water vapor. (District General ATC Permit Condition b)

Verification: As part of the semiannual Air Quality Reports (as required by AQ-43), the project owner shall include an explanation and the date, time, and duration of any violation of this condition.

AQ-9 The facility shall not discharge into the atmosphere from any source particulate matter in excess of 0.3 grains per cubic foot of gas at standard conditions. When the source involves a combustion process, the concentration must be calculated to 12 per cent carbon dioxide (CO_2). (District General ATC Permit Condition c)

Verification: As part of the annual Air Quality Reports, the project owner shall submit to the District and CPM the annual source test and specify the level of particulate matter in grains per cubic foot of gas at standard conditions.

AQ-10 Facility shall not discharge in any one hour from any source whatsoever fumes in total quantities in excess of the amounts as prescribe for and shown in District's Rule 3.3 Table of Allowable Rate of Emission Based on Process Weight Rate. (District General ATC Permit Condition d)

Verification: As part of the semiannual Air Quality Reports (as required by AQ-43), the project owner shall indicate the date, time, and duration of any violation of this condition.

AQ-11 The facility shall not discharge into the atmosphere from any single source of emission whatsoever, any sulfur oxides in excess of 0.2 percent by volume (2,000 ppm) collectively calculated as sulfur dioxide (SO_2). (District General ATC Permit Condition e)

Verification: As part of the annual Air Quality Reports, the project owner shall submit to the District and CPM the annual source test and specify the level of sulfur oxides in percent by volume of gas at standard conditions.

AQ-12 Project owner shall not build, erect, install, or use any article, machine, equipment or other contrivance to conceal an emission which would otherwise constitute a violation of the Health and Safety Code of the State of California or of these Rules and Regulations. (FRAQMD General ATC Permit Condition f)

Verification: Refer to AQ-34 through AQ-36. The project owner shall obtain approval from the District and the CPM prior to installing any new equipment that results in releasing air contaminants.

AQ-13 Project owner shall take every reasonable precaution not to cause or allow the emissions of fugitive dust from being airborne beyond the property line from which the emission originates, from any construction, handling or storage activity, or any wrecking, excavation, grading, clearing of land or solid waste disposal operation. Reasonable precautions shall include, but are not limited to: Use, where possible, of water or chemicals for control of dust in the demolition of existing buildings or structures, construction operations, construction of roadways, or the clearing of land; Application of asphalt, oil, water, or suitable chemical on dirt roads, material stockpiles, and other surfaces which can give rise to airborne dusts; Other means approved by the Air Pollution Control Officer. (FRAQMD General ATC Permit Condition g)

Verification: Refer to conditions AQ-1 through AQ-6.

AQ-14 In the case of shut-down or re-start of air pollution equipment for necessary scheduled maintenance, the intent to shut down such equipment shall be reported to the Air Pollution Control Officer at least twenty-four (24) hours prior to the planned shutdown. Such prior notice may include, but is not limited to the following:

a. Identification of the specific equipment to be taken out of service as well as its location and permit number;

b. The expected length of time that the air pollution control equipment will be out of service;

c. The nature and quantity of emissions of air contaminants likely to occur during the shut-down period;

d. Measures such as the use of off-shift labor and equipment that will be taken to minimize the length of the shutdown period;

e. The reasons that it would be impossible or impractical to shut down the source operation during the maintenance period. (FRAQMD General ATC Permit Condition h)

Verification: As part of the semiannual Air Quality Report (as required by AQ-43), the project owner shall include the dates of the equipment maintenance schedule including when each piece of equipment will be shut-down and when it will start-up.

AQ-15 In the event that any emission source, air pollution control equipment, or related facility breaks down in such a manner which may cause the emission of air contaminants in violation of any permit condition or applicable rules or regulations, other than as exempted here in, the shall immediately notify the Air Pollution Control Officer of such failure or breakdown and subsequently provide a written statement giving all pertinent facts, including the estimated duration of the breakdown. The Air Pollution Control Officer shall be notified when the condition causing the failure or breakdown has been corrected and the equipment is again in operation. (FRAQMD General ATC Permit Condition i)

Verification: As part of the semiannual Air Quality Report (as required by AQ-43), the project owner shall include the date and duration of all equipment breakdowns, the cause of the breakdown, how it was corrected, and the measures that will be used to prevent the problem from occurring again.

AQ-16 Project owner shall submit an application for a Federal Operating Permit Title-V within 12 months after operational startup. (FRAQMD General ATC Permit Condition j)

Verification: The project owner shall submit to the CPM a copy of the report at the time of filing it to the District.

AQ-17 Project owner shall prepare and submit to the District a Toxic Hot Spots emission inventory by the first month of August following the first full calendar year of facility operational history. (FRAQMD General ATC Permit Condition k)

Verification: As part of the semiannual Air Quality Report (as required by AQ-43), the project owner shall submit to the District and the CPM an inventory of all Toxic Hot Spots emissions.

AQ-18 A PSD permit must be obtained from the USEPA before commencement of facility operations. (FRAQMD General ATC Permit Condition L.)

Verification: At least 90 days prior to commencement of facility operations, the project owner shall submit to the CPM a copy of the PSD permit from the US EPA.

AQ-19 The equipment is subject to the federal NSPS codified at 40 CFR Part 60, Subparts A (General Provisions), Db (Standards of Performance for Industrial-Commercial-Institutional Steam Generating Systems), and GG (Standards of Performance for Stationary Gas Turbines), Compliance with all applicable provisions of these regulations is required. (FRAQMD General ATC Permit Condition m)

Verification: As part of the first semi-annual Air Quality Report, the project owner shall submit to the District and CPM a copy of a statement of compliance with the above federal applicable provisions and regulations.

AQ-20 Project owner shall meet the provisions of the Federal Acid Rain Program Title-IV by filing an Acid Rain permit 24 months before operational startup and by certifying CEMS for NOx and O_2 within 90 days after operational startup. (FRAQMD General ATC Permit Condition n)

Verification: The project owner shall provide the District and the CPM with a copy of the Acid Rain permit within 90 days after the permit is approved. Refer to AQ-33 for verification.

AQ-21 Project owner shall file an RMP with the Sutter County office in charge of the prevention of accidental releases prior to operational startup. (FRAQM General ATC Permit Condition o)

Verification: Refer to Hazardous Materials conditions and verifications HazMat-2..

AQ-22 The Athority To Construct (ATC) is not transferable from one location to another, or from one person to another without the written approval of the APCO. (FRAQMD General ATC Permit Condition p)

Verification: At least sixty days in advance, the project owner shall notify, in writing, the District and the CPM of any intended transfer of ownership or location and obtain written approval prior to any transfer.

AQ-23 District personnel shall be allowed access to the plant site and pertinent records at all reasonable times for the purposes of inspections, surveys, collecting samples, obtaining data, reviewing and copying air contaminant emission records and otherwise conducting all necessary functions related to this permit. (FRAQMD General ATC Permit Condition q)

Verification: During site inspection, the project owner/operator shall make the plant logs available to the District, California Air Resources Board (CARB), and Commission staff.

AQ-24 Project owner shall maintain a copy of all District permits at the facility. (FRAQMD General ATC Permit Condition r)

Verification: During site inspection, the project owner/operator shall make all plant permits available to the District, California Air Resources Board (CARB), and Commission staff.

AQ-25 Combustion turbine exhaust stacks shall exhaust at a height of 145 feet and the maximum diameter shall not exceed 18 feet. (FRAQMD General ATC Permit Condition s)

Verification: The project owner/operator shall make the site available for inspection to the District, California Air Resources Board (CARB), and Commission staff.

AQ-26 Project owner shall submit to the District and the Energy Commission ERC option contracts or final signed contracts for the project's ERC liability, except for PM10, as listed in condition AQ-42 prior to the Energy Commission's Final Decision on the project. (FRAQMD General ATC Permit Condition t)

Verification: At least 10 days prior to the Commission adoption of the final decision on the project, the Project owner shall have provided copies of all option contracts or signed contracts required by this condition.

AQ-27 The following Sutter County roads and corresponding miles are to be paved prior to operational startup of the project by the Project owner in order to obtain a portion of the PM10 ERC credits, as indicated in AQ-42:

Roads	Length to be paved (miles)
McClatchy	0.7
Schlag	0.5
Boulton	3.5
Pierce	0.9

a. The location and distance of the roads above may be changed provided that the total offset PM10 ERC credits remain the same, and that the District and CPM is notified, in writing, prior to the start of project construction.

b. Project owner shall provide, prior to start of construction, a copy of an executed legally binding contract between project owner and Sutter County that ensures the paving and maintenance of said roads and which provides conditions enforceable by the District. (FRAQMD General ATC Permit Condition u)

Verification: At least 30 days prior to the start of construction, project owner shall submit to the District and CPM a copy of the required contract.

AQ-28 Calpine has produced evidence indicating that it has an enforceable right to ERCs located in another District. These ERCs cannot be used until the District Board adopts an approving resolution and enters into an MOU with the other District. The District intends to act on the resolution and MOU as soon as practicable after CEC completes an environmental analysis document and the criteria in Section 15253, Subdivison (b) of the CEQA Guidelines are met.(FRAQMD General ATC Permit Condition v)

Verification: At least 30 days prior to the start of construction, Project owner shall provide a copy of the signed MOU to the CPM.

AQ-29 Project owner may substitute interpollutant offsets of VOCs (ROCs) for NOx at a 2.0 to 1.0 interpollutant offset ratio pursuant to Rule 10.1, Section E.2, d. (FRAQMD General ATC Permit Condition w)

Verification: The project owner shall submit to the District and the CPM a copy of the offsets calculations that satisfy AQ-42 if they choose to use the interpollutant substitution offset ratio specified in this condition.

AQ-30 The facility shall exclusively use California PUC pipeline quality natural gas as fuel. The fuel gas total sulfur and heat content will be determined and reported to the District by collecting and analyzing a sample on a monthly basis or by providing monthly certification of the natural gas total sulfur and/or heat content issued by the natural gas distributor. (FRAQMD General ATC Permit Condition x)

Verification: As part of the semi-annual Air Quality Report (as required by AQ-43), the project owner shall submit to the District and CPM a copy of the natural gas analysis or certification issued by the natural gas distributor to satisfy this condition.

AQ-31 All basic and control equipment is to be operated and maintained in accordance with vendors recommended practices and procedures. (FRAQMD General ATC Permit Condition y)

Verification: Refer to AQ-14 verification.

AQ-32 The maximum heat input allowed to each permitted internal and external combustion emissions unit, expressed in MMBtu units on a High Heating

Value basis (HHV), shall not exceed the limits indicated in the table below: (FRAQMD specific ATC Permit Condition a)

Emission Unit	MMBtu/hour (1)	MMBtu/day (2)	MMBtu/year (3)
CTG-1	1,900	45,600	16,644,000
CTG-2	1,900	45,600	16,644,000
Duct Burners-1	170	4,080	928,200
Duct Burners-2	170	4,080	928,200

(1) Based on a rolling three-(3) hour average
(2) Based on 24 hour-day
(3) Based on 365 days/year

Verification: As part of the semi-annual Air Quality Reports (as required by AQ-43), the project owner shall document the date and time when the hourly fuel consumption exceeds the hourly limits included in this condition. The reports shall include a summary of hourly and daily fuel consumption in MMBtu [high heating value (HHV)] for all the cases indicated in the table above. The January Air Quality Report shall also include information on the amount of fuel consumed, in MMBtu (HHV), in the prior calendar year.

AQ-33 The following definitions and limitations shall apply: (FRAQMD specific ATC Permit Condition b)

(1) Startups are defined as the time period commencing with the introduction of fuel flow to the gas turbine and ending when the NOx concentrations do not exceed 2.5 ppmvd at 15% O2 averaged over 1-hour.

(2) Cold Startups are those that occur after the CTG has not been in operation for more than 72 hours.

(3) For each CTG, the Cold Startup shall not exceed 180 consecutive minutes.

(4) Hot Startups are startups that are not Cold Startups.

(5) The maximum allowable NOx emissions for Hot and Cold Startups from each CTG shall not exceed 519 lb/day.

(6) For each CTG, the Hot Startup shall not exceed 60 consecutive minutes.

(7) Shutdowns are defined as the time period commencing with a 15 minute period during which the 15 minute average NOx concentrations exceed 2.5 ppmvd at 15% O_2 and ending when the fuel flow to the gas turbine is discontinued.

(8) For each CTG, the Shutdown shall not exceed 60 consecutive minutes.

(9) The maximum duration of Cold Startups per CTG shall be 150 hours per year and 39 hours per calendar quarter.

(10) The maximum duration of Hot Startups per CTG shall be 250 hours per year, and 63 hours per calendar quarter.

(11) The maximum duration of Shutdowns per CTG shall be 300 hours per year, and 76 hours per calendar quarter.

(12) Compliance with the above yearly limits shall be calculated based on a rolling 12 month average.

(13) All emissions during startups and shutdowns shall be included in all calculations of daily and annual mass emissions required by this permit.

(14) For each CTG the maximum number of Duct Burner hours of operation shall not exceed 5,460 per calendar year.

(15) For each CTG the maximum number of Power Augmentation Steam Injection hours shall not exceed 2,000 per calendar year.

(16) For each CTG the maximum hourly emission rates (lbs/hr) (for a cold startup not to exceed 120 minutes of uncontrolled emissions) are given in the table below:

Pollutant	CTG	Duct Burner	Steam Injection	Hot Start-up	Cold Start-up	Shutdown
NOx	16.8	1.4	0.9	170	175	26.6
CO	16.7	3.4	14.2	902	838	98.2
VOC	1.5	2.0	0.01	7.2	7.2	7.2
SO2	3.7	0.005	0.31	2.3	2.3	2.3
PM10	9.0	2.5	0.0	6.7	6.7	6.7

(17) For maximum project daily emissions (lbs/day) are given in the table below:

	CTG	Duct Burner	Steam In-jection	Hot Start-up	Cold Start-up	Shutdown	Total Emission Per CTG	Calpine Maximum SPP Daily Emissions
NOx	318.3	29.9	17.5	170	349	24	909	1817
CO	317.3	74.8	269.5	902	1,675	25	3264	6528
VOC	28.5	44.9	0.2	1.1	2	2.2	79	158
SO2	70.3	0.12	5.9	2.7	5	5.3	90	179
PM10	171.0	54.6	-	9.0	18	18	271	541

(18) The maximum quarterly emissions for the facility are given in the table below:

	January-March lb/quarter	April-June lb/quarter	July-Sept. lb/quarter	October-December lb/quarter
NOx	102,500	102,500	102,500	102,500
CO	241,600	241,600	241,600	241,600
VOC	11,850	11,850	11,850	11,850
SO2	15,750	15,750	15,750	15,750
PM10	46,200	46,200	46,200	46,200

(19) The maximum annual calendar year emissions (tons/year) for the facility are given in the table below:

	CTG	Duct Burner	Steam Injec.	Hot Start-up	Cold Start-up	Shut-down	Total Emission Per CTG	Calpine Annual SPP Emission
Hrs/Yr.	8,110	5,460	2,000	250	100	300		
NOx	65.9	3.7	0.9	21.2	8.7	1.8	102	205.86
CO	61.6	9.3	14.2	113	41.9	1.9	242	483.18
VOC	5.9	5.6	0.01	0.1	0.1	0.2	11.9	24.41
SO2	14.6	0.01	0.3	0.3	0.1	0.4	15.7	31.5
PM10	36.5	6.8	0.0	1.1	0.5	1.4	46.2	92.5

Verification: As part of the semi-annual Air Quality Report (as required by AQ-43); the project owner shall provide all data required in this condition. In the semi-annual Air Quality Reports (as required by AQ-43), the project owner shall indicate the date, time, and duration of any violation to the NO_x, and VOC limits presented in this condition. The project owner shall include in the semi-annual Air Quality Reports (as required by AQ-43) daily and annual emissions as required in this condition.

AQ-34 BACT Emission Limits:

The BACT emission limits (including duct burners emissions) specified in Conditions (a), (b), (c), (d), and (e) apply under all operating load rates except during CTG startups and shutdowns, as defined in Condition AQ-33. (FRAQMD specific ATC Permit Condition c)

(a) NOx emission concentrations shall be limited to 2.5 ppmvd @ 15% O2 on a 1 hour rolling average (based on readings taken at 15 minute intervals) and with a maximum of 10 ppmvd ammonia slip.

(b) CO emission concentrations shall be limited to 4.0 ppmvd @ 15% O2, on a calendar day average.

(c) VOC emission concentrations shall be limited to 1 ppmvd @ 15% O2, on a calendar day average.

(d) PM10 emissions shall be limited to 11.5 pounds per hour, on a calendar day average.

(e) SO2 emission concentrations shall be limited to 1 ppmvd @ 15% O2, on a calendar day average.

Verification: At lease sixty (60) days before conducting a source test, the project owner shall submit to the District and the CPM a detailed performance annual source test procedure designed to satisfy the requirements of this condition for their review. The project owner shall incorporate the District's and Commission's comments on or modifications to the procedure if any are received. The project owner shall also notify the District and the CPM within seven (7) working days before the project begins initial operation and/or plans to conduct source test as required by this condition. All source test results shall be submitted to the CPM and District within 30 days of the date of the tests.

AQ-35 Each CTG set exhaust vent stack shall be equipped with NOx and % oxygen (O2) CEMs in order to analyze and record exhaust gas flow rate and concentrations. CO, PM10, SO2, and VOC emissions shall be monitored by the CEMs, using source test derived algorithms as indicated in (e) below. In the event that test results show that CO emission limits are exceeded, the APCO may require CEMs for recording concentrations of CO.

(a) The NOx CEMs shall have the capability of recording NOx concentrations during all operating conditions, including startups and shutdowns.

(b) Relative accuracy testing shall be performed on the CEMs on a semi-annual basis or as required by the Acid Rain requirements in Title 40, CFR, Part 75, Appendix B. (FRAQMD specific ATC Permit Condition d)

Verification: At least one hundred and twenty (120) days before initial operation, the project owner shall submit to the District and the CPM a continuous emissions monitoring procedure. Within sixty (60) days of receipt of the procedure, the District and the CPM will advise the project owner of the acceptability of the procedure. Based on the results of the source test identified in AQ-36, the District and CPM may require CEMs for recording concentrations of CO.

AQ-36 Within ninety days after the start of commercial operation of the SPP, source testing shall be performed to determine the mass emission rates and concentrations of NOx, CO, VOC, and SO2 emissions at four different steady-state CTG load rates over the expected operating range of either combustion turbine, as required by 40 CFR 60.335.c (2). The source testing will be used to determine compliance with the permitted emission limits indicated in Specific ATC Permit Conditions (b) and (c). Source testing shall be conducted to determine PM10 mass emissions and concentrations while the CTG is operating at 100 percent load with and without the duct burners, firing at the maximum rated capacity or 170 MMBtu/hr (HHV), whichever is greater.

(a) The source testing results shall be used to develop predictive emission algorithms to estimate mass emission rates for CO, VOC, and SO2, and PM10 emissions.

(b) Source testing to determine the mass emission rates and concentrations of NOx shall be conducted annually after the initial source test indicated in e) above.

(c) Source testing to determine the mass emission rates and concentrations of CO, VOC, SO2 and PM10 shall be conducted annually. The Air Pollution Control Officer may waive annual source testing requirements if prior test results indicate an adequate compliance margin has been maintained. (FRAQMD specific ATC Permit Condition e)

Verification: At least sixty (60) days before the start of commercial operation of the project, the project owner shall submit to the District and the CPM for review a detailed performance test procedure necessary to comply with this condition. The project owner shall incorporate the District and CPM's comments on or modifications to the procedure. At least sixty (60) days prior to any subsequent annual compliance source tests, the project owner shall submit to the District and the CPM for review any proposed changes to the original source test procedure. The project owner shall incorporate the District's and CPM's comments on or modifications to the annual source test procedure.

The project owner shall also notify the District and the CPM within seven (7) working days before the project begins initial operation and/or plans to conduct source testing as required by this condition. Source test results shall be submitted to the District and the CPM within 30 days of the date of the tests.

AQ-37 Source tests to determine ammonia slip shall be conducted within ninety days after commercial operation of the SPP and thereafter as required by the APCO. (FRAQMD specific ATC Permit Condition f)

Verification: Please refer to AQ-36 verification.

AQ-38 The maximum allowable ammonia injection rate to each of the SCR systems shall be 25 pounds per hour. This injection rate may be set at a lower limit based on source tests results. (FRAQMD specific ATC Permit Condition g)

Verification: Please refer to AQ-34 verification.

AQ-39 Within ninety days after beginning commercial operation of the SPP, cold startup, hot startup, and shutdown source tests shall be conducted to determine the emissions of CO and NOx. The APCO may approve the use of the NOx CEMS readings in lieu of source testing if annual Relative Accuracy Testing Audits (RATA) testing is provided. (FRAQMD specific ATC Permit Condition h)

Verification: Within ninety days after the start of commercial operation of the project, the project owner shall submit to the District and the CPM for review a detailed performance source test procedure designed to satisfy the requirements of this condition. The project owner shall incorporate the District's and Commission's comments on or modifications to the procedure. The project owner shall also notify the District and the CPM within seven (7) working days before the project begins commercial operation and/or plans to conduct source test as required by this condition. Source test results shall be submitted to the District within 30 days of the date of the tests.

AQ-40 Records and logs of all data generated by CEMS and algorithms shall be maintained for a period of five (5) years. (FRAQMD specific ATC Permit Condition i)

Verification: During site inspection, the project owner shall make all data generated by the CEMS and algorithm, and included in the plant logs for a period of five years, available to the District, California Air Resources Board (CARB), and the Commission staff.

AQ-41 The project owner shall provide calendar quarterly reports to the District in a format determined in consultation with the District. The calendar quarterly reports shall include the following: CEMS and predictive algorithm emissions data; CTG and duct burner fuel use and operating hours; power augmentation steam injection rates and hours of operation; ammonia injection rates; emission control systems and CEMS hours of operation including the time, date, duration, and reason for any malfunctions of these systems; the number of hot startups, cold startups, and shutdowns; and the electrical and steam production rates. These data shall be averaged on a daily basis, except where required to demonstrate compliance with an emission limitation. (FRAQMD specific ATC Permit Condition j)

Verification: Within 30 days of the end of the calendar quarter, the project owner shall provide to the District and CPM the data required in this condition.

AQ-42 Prior to the start of construction, the SPP facility must provide ERC certificates for NOx, ROC, and PM10, as indicated in the table below. (A portion of required PM10 ERCs and offsets are to be provided by AQ-27.) The ERC sources are Atlantic Oil Company, PG&E, Tri Union, and Rosboro Lumber, as specified in Air Quality Table 16 of the FSA. (FRAQMD specific ATC Permit Condition k)

Verification: At least 30 days prior to the start of constuction, the project owner must submit a copy of the required ERC certificates to the CPM and the District.

	January-March (pounds)	April-June (pounds)	July-September (pounds)	October-December (pounds)	Total ERCs & Offsets	
					Total Pounds	Total Tons
Required NOx	170,061	170,037	170,012	171,535	681,643	340.8
Required VOC	14,797	14,796	14,797	15,558	59,949	29.92
Required PM10	55,440	55,440	55,440	55,440	221,760	110.9

AQ-43 The project owner must file a semi-annual air quality report with the CPM documenting the information required by these conditions and verifications.

Verification: The semi-annual Air Quality report (as required by AQ-43) must be submitted to the CPM within 30 days of the end of the 6 month reporting period.

REFERENCES

Calpine (Calpine Corporation). 1997. Application for Certification, Sutter Power Project (97-AFC-2). Submitted to the California Energy Commission, December 15, 1997.

Calpine (Calpine Corporation). 1998a. Additional Data for Sutter Power Plant (97-AFC-2). Submitted to the California Energy Commission, January 8, 1998.

Calpine (Calpine Corporation). 1998e. Sutter Power Plant Prevention of Significant Deterioration Permit Application. Submitted to the California Energy Commission, February 10, 1998.

Calpine (Calpine Corporation). 1998f. Sutter Power Plant, Responses to February 2, 1998 Data Requests. Submitted to the California Energy Commission, March 4, 1998.

Calpine (Calpine Corporation). 1998i. Cooling Tower Information. Submitted to the California Energy Commission, May 22, 1998.

Calpine (Calpine Corporation). 1998j. Response to data requests 64 and 66 with additions to 63, 67 and 68. Submitted to the California Energy Commission, May 1, 1998.

CEC (California Energy Commission). 1998a. Data Requests Numbers 1 through 59. Submitted to Charlene Wardlow, Calpine Corporation, February 2, 1998.

CEC (California Energy Commission). 1998c. March 25 and March 31 workshop Data Requests 60 through 69. Submitted to Charlene Wardlow and Curt Hildebrand, Calpine Power project, April 7, 1998.

Foster Wheeler (Foster Wheeler Environmental Corporation). 1998. Oxides of Nitrogen Isopleths for Sutter Power Project's PSD Permit Application. Submitted to the California Energy Commission, March 27, 1998.

Calpine (Calpine Corporation). 1998i. Cooling Tower Information. Submitted to the California Energy Commission, September 22, 1998.

Appendix H

Errata for Air Quality Testimony
Filed on Nov. 17, 1998;
Dated Nov. 30, 1998

Sierra Nevada Customer Service Region

FINAL STAFF ASSESSMENT

ERRATA FOR AIR QUALITY TESTIMONY FILED ON NOVEMBER 17, 1998

BY

MAGDY BADR

LAWS, ORDINANCES, REGULATIONS AND STANDARDS

FEDERAL

The federal New Source Review (NSR) program, which is administered by the District requires the SPP to comply with the Lowest Achievable Emission Rate (LAER) for NOx, VOC and CO and to provide offsets for emissions of these pollutants. In addition, Calpine must certify that all facilities they own and operate comply with applicable requirements contained in the State Implementation Plan. The Environmental Protection Agency (EPA) has revoked the one hour ozone standard for the northern portion of Sutter County in which the SPP will be located, as of July 1998, and it has been replaced by the new 8-hour ozone standard. However, the existing District NSR rules will remain in effect until rules based on the new 8-hour ozone standard are developed and adopted. Therefore, the Calpine project must still comply with all existing Federal NSR rules.

The SPP facility is located in an attainment area for NO2, SO2 PM10 and CO, and is subject to the Prevention of Significant Deterioration (PSD) review for those air contaminants. In general, the project must comply with Best Available Control Technology (BACT) for NO2, SO2, PM10 and CO and demonstrate that its emission impacts will not significantly degrade the existing ambient air quality in the region. EPA Region IX retains PSD review authority. The PSD trigger levels are 40 tons per year for NOx, CO, VOC and SO2 and 15 tons for PM10. The SPP is subject to PSD review for NOx, CO and PM10 since the annual emission levels are higher than the PSD trigger levels.

The power plant's gas turbines are also subject to the federal New Source Performance Standards (NSPS). These standards include a NOx emissions of no more than 75 ppm at 15 percent excess oxygen (ppm@15%O2), and a SOx emissions of no more than 150 ppm@15%O2.

States are required by Title V of the Federal Clean Air Act (FCAA) to implement and administer the operating permit programs with the goal of ensuring that large sources are in compliance with all applicable requirements. These requirements are contained in Title 40 CFR, part 70. To comply with Title V, the District has the authority to administer the federal operating permit program and has adopted Regulation X, Rule 10.3. The Acid Rain Provisions of the FCAA establish an emission allowance/tracking program and impose monitoring of SO2 and NOx emissions. All electrical generating facilities labeled as "affected units" are subject to acid rain regulations. The SPP is subject to acid rain regulations and must comply with all requirements. Calpine will estimate SO2 emissions using the approved emission factors and measured heat input rate. The CO2 emissions are estimated using a carbon balance for natural gas and measured heat input. The heat input will be monitored on a continuous basis with an accuracy of $\pm$ 2 percent. The heat content of the natural gas will be measured or certified monthly by the natural gas distributor. Furthermore, the SPP will be required to install, operate and certify NOx continuous emission monitoring systems (CEMS). All calculation methodologies and CEMS must be installed and certified within 90 days

Regulation X, Rule 10.3 — Requires the preparation and submittal of Title V operating permit and acid rain permit applications. Applications for new sources are due within 12 months of initial operation of the source.

Regulation XI, Rule 11.3 — Restricts the use of hexavalent chromium water treatment chemicals in cooling towers. Limits hexavalent chromium emissions to existing cooling towers.

SETTING

METEOROLOGY AND CLIMATE

The SPP will be located in Sutter County, approximately seven miles southwest of Yuba City, California. It will be constructed on a ~~twelve~~ sixteen acre parcel adjacent to the Greenleaf Unit 1 cogeneration facility. The area surrounding the project site is flat. The Sutter Buttes is the nearest elevated terrain, which is located nine miles north~~east~~ of the project site.

Sutter County is part of the Sacramento Valley Air Basin, which is surrounded by the Coastal Mountain Range to the west, the Sierra Nevada to the east, the Cascade Range to the north and the San Joaquin Valley Air Basin to the south. The Sacramento Valley has a moderate mediterranean climate, which is characterized by hot, dry summers and cool, rainy winters. The annual average rainfall is approximately 17 inches. The majority of the rain falls from October to April. The North Pacific storm track intermittently dominates the Valley weather, with periods of dense and persistent low-level fog often occurring between storms. The frequency and persistence of heavy fog in the Valley diminishes with the approach of spring, when the days lengthen and the intensity of the sun increases.

During the summer, the Pacific storm track is usually north of the Sacramento Valley, the afternoon temperatures are warm to hot, while nights are usually mild due to cool marine air intrusion from the San Francisco Bay Area. Meteorological data collected at the Sacramento Executive Airport (which is over 30 miles away from the project site) indicate that July is usually the warmest month of the year, with a normal daily maximum temperature of 93°F, and a normal daily minimum of 59°F. In the fall and spring, the afternoon temperatures are mild, in the 60's and 70's, while nights are cool, in the 40's and 50's. In the winter, temperatures are cool in the afternoon and crisp at night. The coldest month is usually January, with a normal daily maximum of 53°F and a normal daily minimum of 38°F. The recorded high temperature is 115°F and the recorded low temperature is 18°F.

The prevailing wind is southerly during most of the year. However, in November and December, a large north to south pressure gradient develops over Northern California and northerly winds prevail. Wind directions are often influenced by the topography of the Central Sacramento Valley and the surface pressure gradient between the coast and the Valley. Figures 1 through 5 show the annual and quarterly Windroses

AIR QUALITY Table 8
Maximum Hourly Emissions (lb/hour) Using Westinghouse Turbine

Pollutant	CTG(2)	Duct Burner(3)	Steam Injection	Hot Start-up	Cold Start-up(4)	Shutdown
NOx	16.8	1.4	0.9	170	175	~~26.6~~ 12.1
CO	16.7	3.4	14.2	902	838	~~98.2~~ 12.6
VOC	1.5	2.0	0.01	~~7.2~~ 1.1	~~7.2~~ 1.1	~~7.2~~ 1.1
SO2	3.7	0.005	0.31	~~2.3~~ 2.7	~~2.3~~ 2.7	~~2.3~~ 2.7
PM10	9.0	2.5	0.0	~~6.7~~ 9.0	~~6.7~~ 9.0	~~6.7~~ 9.0

(1) No emissions associated with cooling towers.
(2) All air emissions are calculated based on CTG operation at 20F and 100 percent load rate.
(3) Duct burner emissions are calculated based on firing 170 MMBtu/Hr (HHV) of natural gas.
(4) Cold start-up emission levels represent one hour.

Sources: Calpine (Calpine Corporation). September 22,1998. Cooling Tower Information.
Calpine (Calpine Corporation). 1998j. Response to data requests 64 and 66 with additions to 63, 67 and 68.

AIR QUALITY Table 9 presents the maximum daily emission levels as estimated by Calpine using the assumptions presented above. The air emission levels assume maximum hourly operation of the project per day. Calpine estimates that uncontrolled air emissions associated with cold start-ups are based on 2 hours, which staff believes is sufficient time for the SCR to warm-up and control the NOx emissions consistent with manufacture guarantees.

AIR QUALITY Table 15
SPP Nonreactive Pollutant
Ambient Air Quality ISC Modeling Results

Pollutant	Averaging Period	Project Impact (µg/m3)	Background (µg/m3)	Total Impact (µg/m3)	Limiting Standard (µg/m3)	Type of Standard	Percent of Standard (%)
NO2[1]	1-hour	241.2	150.4	391.6	470	CAAQS	83
	Annual	0.26	31.96	32.2	100	NAAQS	32
PM10[1]	24-hours	0.55	154	154.55	50	CAAQS	309
	Annual	0.097	36.7	36.8	30	CAAQS	123
PM2.5[1]	24-hours	0.55	154	154.55	~~50~~ 65	~~C~~NAAQS	238
	Annual	0.097	36.7	36.8	~~30~~ 15	~~C~~NAAQS	245
CO[1]	1-hour	1243	11.4	1254	23,000	CAAQS	6
	8-hours	305.2	8.3	314	10,000	CAAQS	3
SO2	3-hours	1.3	26.1	27.4	1,300	NAAQS	2
	24-hours	0.6	7.83	7.89	365	NAAQS	8
	Annual	0.1	0.0[3]	0.1	80	NAAQS	0.1

1. The project emissions include emissions during start-up.
2. Background data is based on Yuba City monitoring station.
3. No representative ambient data available within the region.

Source: Calpine (Calpine Corporation). 1997. Pages 8.1-33-35, November 2,1998.

CUMULATIVE IMPACT ANALYSIS

The Energy Commission staff provided Calpine with a modeling protocol to conduct the cumulative impact analysis. The major component of the protocol required Calpine to include in the modeling all known future projects within six miles of the SPP. Then, the modeling results (impacts) would be added to the ambient background levels to establish the total impact. The District conducted a comprehensive review and determined that there are no planned facilities within the six miles that are eligible for modeling. Therefore, the cumulative impact analysis was unnecessary.

The cumulative impacts of the linear facilities reviewed by the Sutter Community Services Department identified that Hughes Road - East Sutter Bypass Canal Bridge replacement is a proposed project with NOx rather than O_2 to form N_2 in the presence of excess O_2 at temperatures in the range of 400 to 750 °F. If the temperature is lower than 400°F, the ammonia reaction rate is low, and therefore, NH_3 emissions (called ammonia slip) will increase.

<u>The DOC identifies Calpine's intention to continue discussions with EPA after the Commission Decision to allow the project to have excursions from this limit under specified circumstances.</u>

<u>SCONOx Technology as An Alternative Mitigation</u>

The SCONOx system uses a catalyst bed which is located inside the HRSG anywhere within a 260 °F to 700 °F temperature range. As hot exhaust gases pass through the catalyst rack, the NOx molecules are adsorbed onto the catalyst surface. When the catalyst is regenerated using a regeneration gas containing 4 percent hydrogen, 3 percent nitrogen, and 1.5 percent carbon dioxide. The regeneration gas is created by reacting natural gas with air in the presence of an electrically heated nickel oxidation catalyst, which is electrically heated to 1900 °F. The gas is then mixed with steam (produced from the HRSG) and passes over a second catalyst to form the regeneration gas. The regeneration gas is introduced into the catalyst rack through a system of piping and louvers. The regeneration gas exits the catalyst rack is ducted back into the HRSG, upstream of the SCONOx.

SCONOX has been evaluated by USEPA Region IX, and they have acknowledged that a 2 ppm @ 15% O_2 NOx control level can be achieved in practice using the technology. Furthermore, USEPA recommended that new sources subject to the BACT requirements in Part C of the CAA should consider the 2.0 ppmv @15% O_2 for three hours avenging time or 2.5 ppmvd @15% O_2 for one hour avenging time as an achievable emissions limit in their BACT analyses.

Control of Carbon Monoxide (CO) and Reactive Organic Gases (ROG)

Combustion turbines inherently generate low CO and ROG emissions. High combustion temperatures, fuel/air mixing, and the excess air inherent in the CTG's combustion process favor complete combustion of fossil fuels. These conditions, however, also lead to higher NO_x emissions. Current CTG designs attempt to balance achieving low NO_x emissions (from the CTG prior to post-combustion controls) while keeping CO and ROG emissions low. Good operating and maintenance practices will be used to limit the project's CO and ROG emissions.

Calpine proposes to install an oxidation catalyst downstream from the CTGs and the duct burners to reduce CO emissions. While the catalyst's ROG removal effectiveness is not guaranteed, the oxidation catalyst, which is a standard design, is expected to reduce ROG emissions by five percent for this project.

Control of PM10

Natural gas fuel contains only trace quantities of noncombustible material. Particulate emissions (PM_{10}) will be controlled by inlet air filtering for the combined cycle CTG and HRSG unit. In addition, Calpine proposes to use a dry cooling tower which has no PM10 emissions associated with its operation, which is the best control technology available.

Sulfur Dioxide Emissions Control

SO2 emissions result from the combustion of any sulfur-bearing fuel. The SPP SO2 emissions will be controlled by burning only natural gas, which typically contains only traces of sulfur. The emissions from the project's CTGs are expected to be very small without any additional post-combustion SO2 control equipment. Since natural gas contains only 2000 grains of sulfur per million cubic feet, the resulting SO2 emission concentrations should be less than 1.0 ppm @15% O_2.

<u>Emission Offsets</u>

General ATC Permit Condition y)

Verification: Refer to AQ-14 verification.

AQ-32 The maximum heat input allowed to each permitted internal and external combustion emissions unit, expressed in MMBtu units on a High Heating Value basis (HHV), shall not exceed the limits indicated in the table below: (FRAQMD specific ATC Permit Condition a)

Emission Unit	MMBtu/hour ~~(1)~~	MMBtu/day (2)	MMBtu/year (3)
CTG-1	1,900	45,600	16,644,000
CTG-2	1,900	45,600	16,644,000
Duct Burners-1	170	4,080	928,200
Duct Burners-2	170	4,080	928,200

~~(1) Based on a rolling three (3) hour average~~
(2) Based on 24 hour-day
(3) Based on 365 days/year

Verification: As part of the semi-annual Air Quality Reports (as required by AQ-43), the project owner shall document the date and time when the hourly fuel consumption exceeds the hourly limits included in this condition. The reports shall include a summary of hourly and daily fuel consumption in MMBtu [high heating value (HHV)] for all the cases indicated in the table above. The January Air Quality Report shall also include information on the amount of fuel consumed, in MMBtu (HHV), in the prior calendar year.

AQ-33 The following definitions and limitations shall apply: (FRAQMD specific ATC Permit Condition b)

(1) Startups are defined as the time period commencing with the introduction of fuel flow to the gas turbine and ending when the NOx concentrations do not exceed 2.5 ppmvd at 15% O2 averaged over 1-hour.

(2) Cold Startups are those that occur after the CTG has not been in operation for more than 72 hours.

(3) For each CTG, the Cold Startup shall not exceed 180 consecutive minutes.

(4) Hot Startups are startups that are not Cold Startups.

(5) The maximum allowable NOx emissions for Hot and Cold Startups from each CTG shall not exceed 519 lb/day.

(6) For each CTG, the Hot Startup shall not exceed 60 consecutive

(16) For each CTG the maximum hourly emission rates (lbs/hr) (for a cold startup not to exceed 120 minutes of uncontrolled emissions) are given in the table below averaged over any rolling three hour period, except for the NOx emission rate, which will be averaged over one hour period:

Pollutant	**CTG**	**CTG + Duct Burner**	**CTG + Duct Burner + Steam Injection**	**CTG + Steam Injection**	**Hot Start-up**	**Cold Start-up**	**Shut-down**
NOx	16.8	~~1.4~~ 18.2	19.1	~~0.9~~ 17.7	170	175	~~26.6~~ 12.1
CO	16.7	~~3.4~~ 20.1	34.3	~~14.2~~ 30.9	902	838	~~98.2~~ 12.6
VOC	1.5	~~2.0~~ 3.5	3.51	~~0.01~~ 1.51	~~7.2~~ 1.1	~~7.2~~ 1.1	~~7.2~~ 1.1
SO2	3.7	~~0.005~~ 3.71	4.02	~~0.31~~ 4.01	~~2.3~~ 2.7	~~2.3~~ 2.7	~~2.3~~ 2.7
PM10	9.0	~~2.5~~ 11.5	11.5	~~0.0~~ 9.0	~~6.7~~ 9.0	~~6.7~~ 9.0	~~6.7~~ 9.0

(17) For maximum project daily emissions (lbs/day) are given in the table below:

	~~CTG~~	~~Duct Burner~~	~~Steam Injection~~	~~Hot Start-up~~	~~Cold Start-up~~	~~Shutdown~~	Total Emission Per CTG	Calpine Maximum SPP Daily Emissions
NOx	~~318.3~~	~~20.9~~	~~17.5~~	~~170~~	~~349~~	~~24~~	909	1817
CO	~~317.3~~	~~74.8~~	~~269.5~~	~~902~~	~~1,675~~	~~25~~	3264	6528
VOC	~~28.5~~	~~44.9~~	~~0.2~~	~~1.1~~	~~2~~	~~2.2~~	79	158
SO2	~~70.3~~	~~0.12~~	~~5.9~~	~~2.7~~	~~5~~	~~5.3~~	90	179
PM10	~~171.0~~	~~54.6~~	-	~~9.0~~	~~18~~	~~18~~	271	541

(18) The maximum quarterly emissions for the facility are given in the table below:

	January-March lb/quarter	April-June lb/quarter	July-Sept. lb/quarter	October-December lb/quarter
NOx	102,500	102,500	102,500	102,500
CO	241,600	241,600	241,600	241,600
VOC	11,850	11,850	11,850	11,850
SO2	15,750	15,750	15,750	15,750
PM10	46,200	46,200	46,200	46,200

(19) The maximum annual calendar year emissions (tons/year) for the facility are given in the table below:

	~~CTG~~	~~Duct Burner~~	~~Steam Injec.~~	~~Hot Start-up~~	~~Cold Start-up~~	~~Shut-down~~	Total Emission Per CTG	Calpine Annual SPP Emission
~~Hrs/Yr~~	~~8,110~~	~~5,460~~	~~2,000~~	~~250~~	~~100~~	~~300~~		
NOx	~~65.9~~	~~3.7~~	~~0.9~~	~~21.2~~	~~8.7~~	~~1.8~~	102	205.86
CO	~~61.6~~	~~9.3~~	~~14.2~~	~~113~~	~~41.9~~	~~1.9~~	242	483.18
VOC	~~5.9~~	~~5.6~~	~~0.01~~	~~0.1~~	~~0.1~~	~~0.2~~	11.9	24.41
SO2	~~14.6~~	~~0.01~~	~~0.3~~	~~0.3~~	~~0.1~~	~~0.4~~	15.7	31.5
PM10	~~36.5~~	~~6.8~~	~~0.0~~	~~1.1~~	~~0.5~~	~~1.4~~	46.2	92.5

Verification: As part of the semi-annual Air Quality Report (as required by AQ-43), the project owner shall provide all data required in this condition. In the semi-annual Air Quality Reports (as required by AQ-43), the project owner shall indicate the date, time, and duration of any violation to the NO_x, and VOC limits presented in this condition. The project owner shall include in the semi-annual Air Quality Reports (as required by AQ-43) daily and annual emissions as required in this condition.

AQ-34 BACT Emission Limits:

The BACT emission limits (including duct burners emissions) specified in Conditions (a), (b), (c), (d), and (e) apply under all operating load rates except during CTG startups and shutdowns, as defined in Condition AQ-33. (FRAQMD specific ATC Permit Condition c)

(a) NOx emission concentrations shall be limited to 2.5 ppmvd @ 15% O2 on a 1 hour rolling average (based on readings taken at 15 minute intervals) and with a maximum of 10 ppmvd ammonia slip.

(b) CO emission concentrations shall be limited to 4.0 ppmvd @ 15% O2, on a calendar day average.

(c) VOC emission concentrations shall be limited to 1 ppmvd @ 15% O2, on a calendar day average.

(d) PM10 emissions shall be limited to 11.5 pounds per hour, on a calendar day average.

(e) SO2 emission concentrations shall be limited to 1 ppmvd @ 15% O2, on a calendar day average.

Verification: At lease sixty (60) days before conducting a source test, the project owner shall submit to the District and the CPM a detailed performance annual source test procedure designed to satisfy the requirements of this condition for their review. The project owner shall incorporate the District's and Commission's comments on or modifications to the procedure if any are received. The project owner shall also notify the District and the CPM within seven (7) working days before the project begins initial operation and/or plans to conduct source test as required by this condition. All source test results shall be submitted to the CPM and District within 30 days of the date of the tests.

AQ-35 Each CTG set exhaust vent stack shall be equipped with NOx and % oxygen (O2) CEMs in order to analyze and record exhaust gas flow rate and concentrations. CO, PM10, SO2, and VOC emissions shall be monitored by the CEMs, using source test derived algorithms as indicated in ~~(e)~~ AQ-36 below. In the event that test results show that CO emission limits are exceeded, the APCO may require CEMs for recording concentrations of CO.

(a) The NOx CEMs shall have the capability of recording NOx concentrations during all operating conditions, including startups and shutdowns.

(b) Relative accuracy testing shall be performed on the CEMs on a semi-annual basis or as required by the Acid Rain requirements in Title 40, CFR, Part 75, Appendix B. (FRAQMD specific ATC Permit Condition d)

Verification: At least one hundred and twenty (120) days before initial operation, the project owner shall submit to the District and the CPM a continuous emissions monitoring procedure. Within sixty (60) days of receipt of the procedure, the District and the CPM will advise the project owner of the acceptability of the procedure. Based on the results of the source test identified in AQ-36, the District and CPM may require CEMs for recording concentrations of CO.

AQ-36 Within ninety days after the start of commercial operation of the SPP, source testing shall be performed to determine the mass emission rates and concentrations of NOx, CO, VOC, and SO2 emissions at four different steady-state CTG load rates over the expected operating range of either combustion turbine, as required by 40 CFR 60.335.c (2). The source testing will be used to determine compliance with the permitted emission limits indicated in Specific ATC Permit Conditions ~~(b) and (c)~~ AQ-33 and AQ-34. Source testing shall be conducted to determine PM10 mass emissions and concentrations while the CTG is operating at 100 percent load with and without the duct burners, firing at the maximum rated capacity or 170 MMBtu/hr (HHV), whichever is greater.

(a) The source testing results shall be used to develop predictive emission algorithms to estimate mass emission rates for CO, VOC, and SO2, and PM10 emissions.

(b) Source testing to determine the mass emission rates and concentrations of NOx shall be conducted annually after the initial source test indicated in e) above.

(c) Source testing to determine the mass emission rates and concentrations of CO, VOC, SO2 and PM10 shall be conducted annually. The Air Pollution Control Officer may waive annual source testing requirements if prior test results indicate an adequate compliance margin has been maintained. (FRAQMD specific ATC Permit Condition e)

Verification: At least sixty (60) days before the start of commercial operation of the project, the project owner shall submit to the District and the CPM for review a detailed performance test procedure necessary to comply with this condition. The project owner shall incorporate the District and CPM's comments on or modifications to the procedure. At least sixty (60) days prior to any subsequent annual compliance source tests, the project owner shall submit to the District and the CPM for review any proposed changes to the original source test procedure. The project owner shall incorporate the District's and CPM's comments on or modifications to the annual source test procedure.

The project owner shall also notify the District and the CPM within seven (7) working days before the project begins initial operation and/or plans to conduct source testing as required by this condition. Source test results shall be submitted to the District and the CPM within 30 days of the date of the tests.

AQ-37 Source tests to determine ammonia slip shall be conducted within ninety days after commercial operation of the SPP and thereafter as required by the APCO. (FRAQMD specific ATC Permit Condition f)

Verification: Please refer to AQ-36 verification.

AQ-38 The maximum allowable ammonia injection rate to each of the SCR systems shall be 25 pounds per hour under normal operating condition. This injection rate may be adjusted ~~set at a lower limit~~ based on source tests results. (FRAQMD specific ATC Permit Condition g)

Verification: Please refer to AQ-34 verification.

AQ-39 Within ninety days after beginning commercial operation of the SPP, cold startup, hot startup, and shutdown source tests shall be conducted to determine the emissions of CO and NOx. The APCO may approve the use of the NOx CEMS readings in lieu of source testing if annual Relative Accuracy Testing Audits (RATA) testing is provided. (FRAQMD specific ATC Permit Condition h)

Verification: Within ninety days after the start of commercial operation of the project, the project owner shall submit to the District and the CPM for review a detailed performance source test procedure designed to satisfy the requirements of this condition. The project owner shall incorporate the District's and Commission's comments on or modifications to the procedure. The project owner shall also notify the District and the CPM within seven (7) working days before the project begins commercial operation and/or plans to conduct source test as required by this condition. Source test results shall be submitted to the District within 30 days of the date of the tests.

AQ-40 Records and logs of all data generated by CEMS and algorithms shall be maintained for a period of five (5) years. (FRAQMD specific ATC Permit Condition i)

Verification: During site inspection, the project owner shall make all data generated by the CEMS and algorithm, and included in the plant logs for a period of five years, available to the District, California Air Resources Board (CARB), and the Commission staff.

AQ-41 The project owner shall provide calendar quarterly reports to the District in a format determined in consultation with the District. The calendar quarterly reports shall include the following: CEMS and predictive algorithm emissions data; CTG and duct burner fuel use and operating hours; power augmentation steam injection rates and hours of operation; ammonia injection rates; emission control systems and CEMS hours of operation including the time, date, duration, and reason for any malfunctions of these systems; the number of hot startups, cold startups, and shutdowns; and the electrical and steam production rates. These data shall be averaged on a daily basis, except where required to demonstrate compliance with an emission limitation. (FRAQMD specific ATC Permit Condition j)

Verification: Within 30 days of the end of the calendar quarter, the project owner shall provide to the District and CPM the data required in this condition.

AQ-42 Prior to the start of construction, the SPP facility must provide ERC certificates for NOx, ROC, and PM10, as indicated in the table below. (A portion of required PM10 ERCs and offsets are to be provided by AQ-27.) The ERC sources are Atlantic Oil Company, PG&E, Tri Union, and Rosboro Lumber, as specified in Air Quality Table 16 of the FSA. Alternative sources of offsets may be used if they meet the criteria applied to these sources and are approved by the District and CPM. (FRAQMD specific ATC Permit Condition k)

Verification: At least 30 days prior to the start of constuction, the project owner must submit a copy of the required ERC certificates to the CPM and the District.

	January-March (pounds)	April-June (pounds)	July-September (pounds)	October-December (pounds)	Total ERCs & Offsets	
					Total Pounds	Total Tons
Required NOx	170,061	170,037	170,012	171,535	681,643	340.8
Required VOC	14,797	14,796	14,797	15,558	59,949	29.92
Required PM10	55,440	55,440	55,440	55,440	221,760	110.9
These ERCs are based on the appropriate offset distance ratio calculations.						

AQ-43 The project owner must file a semi-annual air quality report with the CPM documenting the information required by these conditions and verifications.

Verification: The semi-annual Air Quality report (as required by AQ-43) must be submitted to the CPM within 30 days of the end of the 6 month reporting period.

Appendix I

Supplemental Testimony for the Sutter Power Project (on Alternative Transmission Line Routes, Socioeconomics, and Plant Closure Fund); Dated Nov. 24, 1998

Sierra Nevada Customer Service Region

State of California

The Resources Agency of California

Memorandum

Date : November 24, 1998

Telephone: ATSS ( )
( )

To : Michal C. Moore, Presiding Member
William J. Keese, Associate

From : California Energy Commission
1516 Ninth Street
Sacramento 95814-5512

Paul Richins, Jr. Paul R
Energy Commission Project Manager

Subject : **SUPPLEMENTAL TESTIMONY FOR THE SUTTER POWER PROJECT (97-AFC-2)**

The November 13, 1998, hearing order required additional information on various topics and related issues being discussed in the Sutter Power Plant project siting case. Attached is supplemental testimony of Paul Richins and Al McCuen on alternative project sites and alternative transmission line routes which address matters contained in paragraph A of the hearing order, supplemental testimony of Amanda Stennick on socioeconomics (paragraph C), supplemental testimony of Steve Munro on plant closure fund (paragraph D), and information on sequencing of the final decision between the Energy Commission and Sutter County Board of Supervisors (paragraph B and E).

cc Sutter Proof of Service List

sutter/letters/sup-test.ltr

DOCKET
97-AFC-2
DATE NOV 2 4 1998
RECD. NOV 2 4 1998

PROOF OF SERVICE (REVISED ________) FILED WITH
ORIGINAL MAILED FROM SACRAMENTO ON 11/25/98
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ALTERNATIVES
Supplemental Testimony of Paul Richins, Jr.

The November 13, 1998, hearing order required supplemental testimony regarding alternatives to the Sutter Power Plant project. Staff understands the hearing order to request (1) a clearer analysis of the pros and cons of the power plant locational alternatives considered by staff, (2) estimated lengths of the linear facilities that would serve these alternative locations, and (3) a fuller discussion of the consequences that may occur if "no project" is built, including the consequences of load growth and voltage support problems in the Sacramento Region and other transmission projects that may become more likely if Calpine's generation project is not built.

Staff examined a five-county region for alternatives, based on prior analysis from the Commission's 1994 Sacramento Ethanol and Power Cogeneration (SEPCO) power plant siting case, Calpine's AFC, and information from Sutter County (including identification of industrial zones within the County). The staff also considered recommendations from the public.

From these sources of information, Staff identified 11 potential alternative sites to the Sutter project site. These 11 sites were further reduced to four sites (see Figure 1, Regional Map) using four screening criteria—(1) proximity to natural gas supply, (2) proximity to transmission lines, (3) transmission line avoidance of medium to high density housing, and (4) whether the site was appropriately zoned.

Below we have compared the mitigated Sutter Power Plant site and its linear facilities against the four alternative project sites. A description and map, and the advantages, disadvantages and potential fatal flaws of each alternative site is provided.

In addition, because the CEQA Guidelines emphasize that the alternatives analysis should focus on sites that would reduce any significant project impacts, Staff has included a brief general assessment of the visual impacts of the various alternative sites. This is because staff's FSA concluded that the Sutter project, with all agreed upon mitigation, will result in significant impacts only with regard to visual resources.

ALTERNATIVES - Figure 1
Regional Map of the Four Project Sites Reviewed

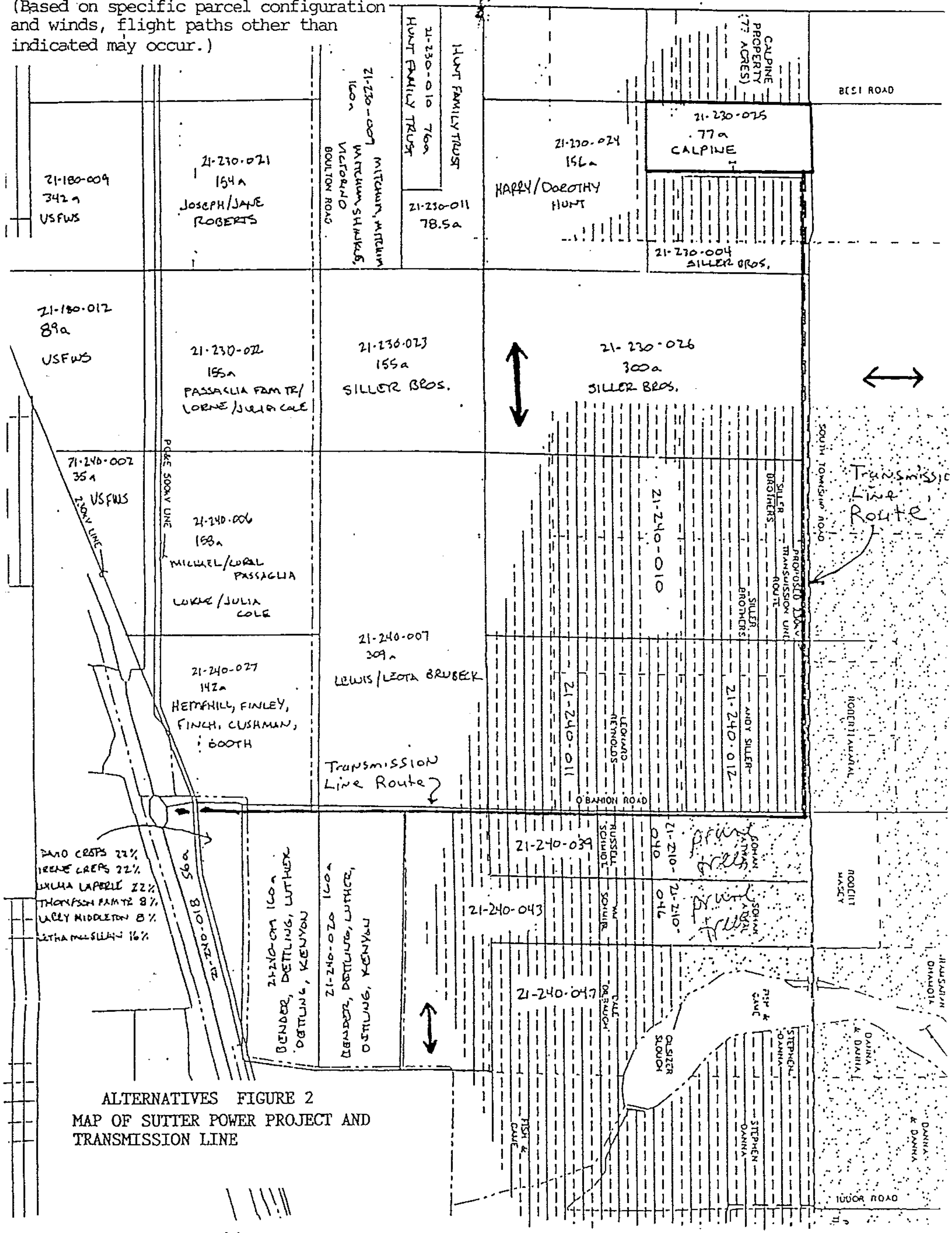
CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, NOVEMBER 1998
SOURCE: California Energy Commission Statewide Transmission Line and Power Plant Maps/1998 & USGS 7.5 Minute Quadrangles

SUTTER POWER PLANT SITE (see Figure 2, Map of the Sutter Power Project)

Site Description

- The 77 acre site is located near the intersection of South Township and Best Roads
- The site is zoned for agricultural uses but has not been cultivated since Greenleaf #1 was built in 1985
- There are nine residences within 1 mile of the site
- Fire protection and emergency services are about 5 miles away
- The closest noise receptor is 1/4 mile away
- The impacts to on-site wetlands are being mitigated off-site
- The site is owned by Calpine Corporation
- A 4-mile transmission line route is proposed to run south along South Township Road and west on O'Banion Road to Western's transmission lines
- The transmission line passes 4 residences
- The switching station (2 acres) is proposed to be located on a portion of a 56 acre parcel at the end of O'Banion Road next to Western's transmission lines
- The 56 acre parcel is currently in rice cultivation and is used as a duck club
- The natural gas line would be about 14 miles long
- Nitrogen oxide emissions from the combustion process will be controlled to 2.5 parts per million
- The plant will utilize 100% dry cooling
- Water usage is 140 gpm
- The dry cooled plant will have zero effluent discharges and will not discharge any process fluids into drainage canals

Flight Directions
(Based on specific parcel configuration and winds, flight paths other than indicated may occur.)



ALTERNATIVES FIGURE 2
MAP OF SUTTER POWER PROJECT AND TRANSMISSION LINE

SACRAMENTO COUNTY SITE (SAC 1) (see Figure 3)

Site Description

- The 19 acre site is adjacent to existing Western transmission line
- Zoning (M-2) and General Plan designations are compatible with industrial use
- Site is in a flood zone and is prone to flooding
- Interconnecting transmission line is about 4,000 feet long
- A separate, off-site switching station would not be required
- Natural gas line would be about 16 miles long

Advantages

- Fire protection and emergency services are only 2 miles away (versus 5 for SPP)
- Interconnecting transmission line would be less than 1 mile long and eliminates impacts on agricultural cultivation activities
- The connecting transmission line would parallel an established corridor
- Interconnection at Elverta Substation provides greater system support (500 MW vs. 350 MW)
- A separate, off-site switching station would not be required
- The site is currently zoned for industrial uses
- The site and the SEPCO project were approved by the Energy Commission in 1994 for a much smaller 113 MW baseload/148 MW peaking plant

Disadvantages

- Site is near a residential area (most lots are 1-2 acre parcels)
- Site is adjacent to areas expected to grow in residential population
- Greater numbers of residences within a 1 mile radius (200 vs. 9) increases the potential impact from a hazardous materials incident
- A greater number of residents and travelers would have their views of the Sierra and Coast ranges negatively impacted by the plant and transmission line
- Jurisdictional wetlands, vernal pools, listed species (fairy shrimp) and special status species (various) would be impacted
- There was significant public opposition to this site during the SEPCO hearings for a plant 1/4 to 1/3 the size of the SPP project
- As a condition for approval, the site was required to be raised ten feet due to flooding (flood zone)

SOUTH SUTTER COUNTY INDUSTRIAL AREA SITE (S. 1) (see Figure 3)

Site Description

- The 33 acre site is located on Sankey Road about 3 miles east of Highway 99 and about 6 miles east of the Sacramento River in South Sutter County
- There are about 40 residences within 1 mile of the site
- Site is zoned agricultural with a General Plan designation of Industrial/Commercial
- The site is currently used for grazing
- A 1 mile connecting transmission line would be necessary and would pass by about 30 residences
- Alternatively, a 5 mile line to Elverta could parallel existing rights of way but would pass more than 150 residences
- Natural gas line would be about 20 miles long

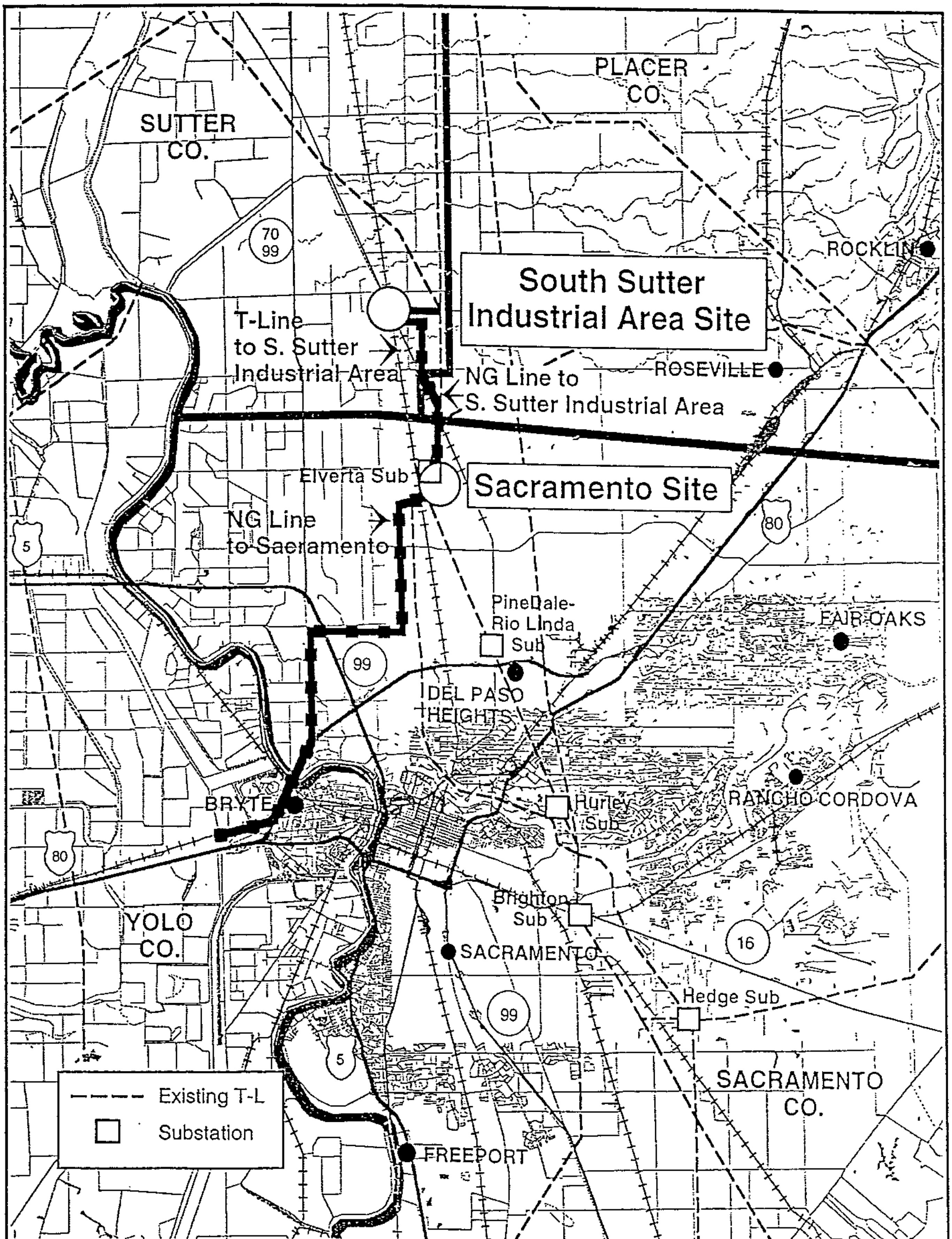
Advantages

- Site has correct General Plan designation but a change in the zoning designation would be required by Sutter County Board of Supervisors

Disadvantages

- Fire protection and emergency services are 20 miles away (versus 5 for SPP)
- A greater number of residents and travelers would have their views of the Sierra and Coast ranges negatively impacted by the plant and transmission line
- Site is adjacent to areas expected to grow in residential population
- Noise impacts are worse than at the proposed site because an occupied dwelling is immediately adjacent to the site
- A ~~greater number of residents and travelers views of the Sierra~~ and Coast ranges ~~would be impacted by the plant~~ and transmission line
- Jurisdictional wetlands, vernal pools, listed species (fairy shrimp) and special status species (various) would be potentially impacted
- The site does not have access to the proper public facilities (sewer, water, storm drainage) as required by the General Plan for development in this portion of the County
- There is no "for sale" signage on the parcel, site control is unknown

ALTERNATIVES - Figure 3
Sacramento County Site and the South Sutter County Industrial Site



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, NOVEMBER 1998
SOURCE: California Energy Commission Statewide Transmission Line and Power Plant Maps/1998 & USGS 7.5 Minute Quadrangles

SUTTER BUTTES INDUSTRIAL AREA SITE (S.B.) (see Figure 4)

Site Description

- The 67 acre site is located at the intersection of Highway 20 and Acacia Ave in the Sutter Buttes Industrial Area
- There are about 40 residences within 1 mile of the site
- The site has a general plan designation of Industrial/Commercial and is zoned M-2
- The connecting transmission line would be 5 miles long passing by about 10 residences and through agriculture lands
- Natural gas line would be about 28 miles long

Advantages

- Fire protection and emergency services are 1 mile away (versus 5 for SPP)
- The site is zoned for industrial uses
- The site is for sale

Disadvantages

- Greater numbers of residences within a 1 mile radius (~40 vs. 9) increases potential impact in the event of a hazardous materials incident
- The interconnection transmission line is 5 miles (vs. 4 miles for SPP)
- The interconnection transmission line impacts a greater number of residences (10 vs. 4)
- Greater potential for impacts and conflicts with agricultural activities
- Potential for a greater impact to visual resources due to increased number of homes and traffic on Highway 20

Potential "Show-stopper"

The plant at this site would be in direct conflict with the Sutter County General Plan policy which requires that new development along Highway 20 be designed to protect the views of the Sutter Buttes. County staff is expected to propose a height restriction for the Sutter Buttes Industrial Area that would prevent any construction of a structure greater than about 50-60 feet. The SPP stacks, heat recovery steam generators and the air cooled condenser range in height from 85 to 145 feet.

O'BANION ROAD SITE (see Figure 4)

Site Description

- The 56 acre site is adjacent to the Western Transmission Line at the west end of O'Banion Road on the south side of the road
- Site is zoned for agriculture uses and is in rice production with a duck club
- No connecting transmission line would be necessary
- The switching station would be adjacent to the power plant
- Natural gas line would be about 16 miles long
- There is one residence within 1 mile of the site

Advantages

- Only one residence is within a 1 mile radius (vs. 9) reduces the potential impacts in the event of a hazardous materials incident
- Lack of an interconnecting transmission line eliminates impacts on off-site agricultural cultivation activities and visual impacts of a transmission line
- The closest noise receptor is farther away (1/2 mile vs. 1/4 mile at SPP).
- There are no wetlands on the site
- No transmission line means no bird collisions with a line
- A separate switching station would not be required

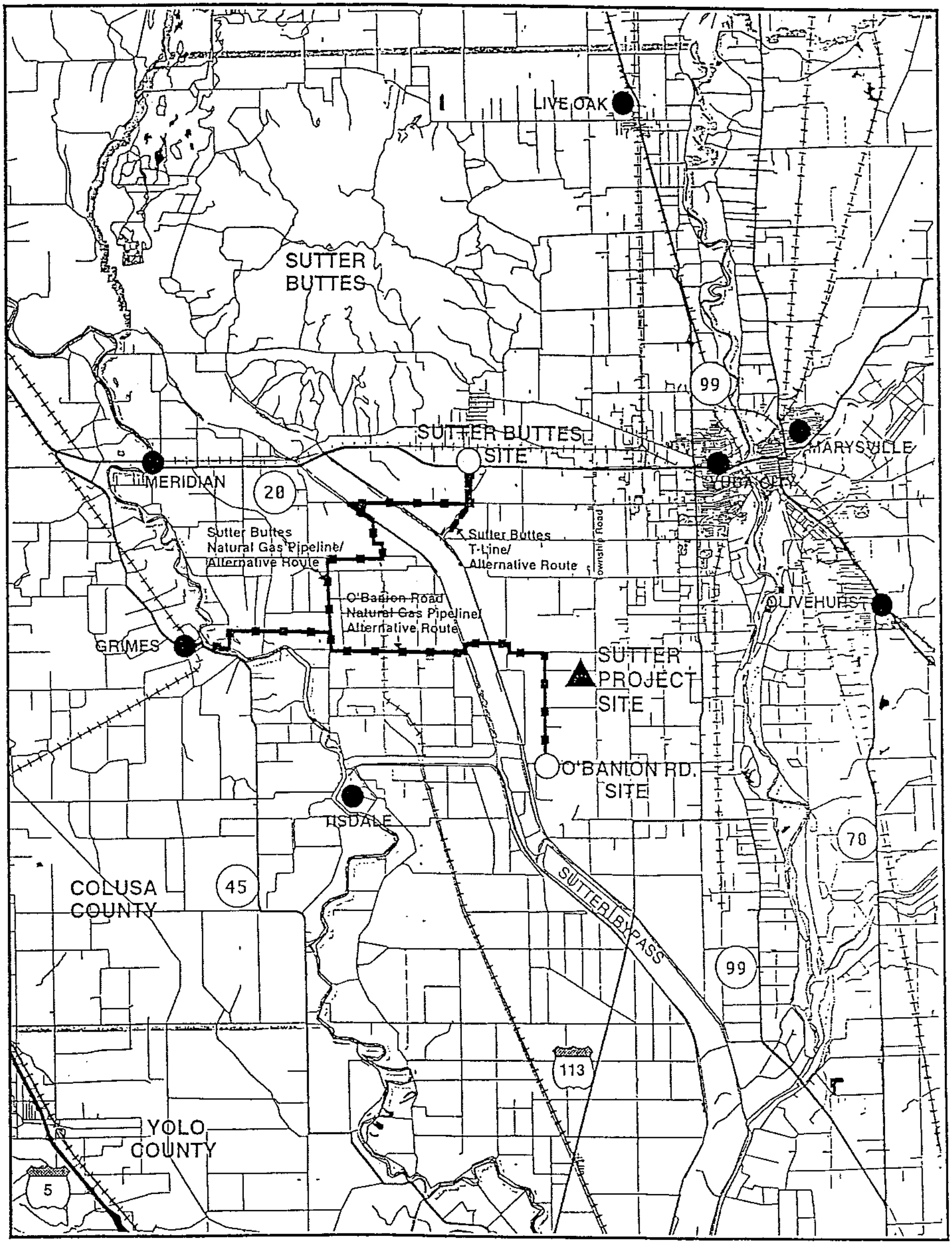
Disadvantages

- Fire protection and emergency services are 9 miles away (versus 5 for SPP)
- At a minimum, 16 acres of cultivated land would be permanently removed from production. If the entire parcel is affected, 56 acres would be removed.
- US Fish and Wildlife Service believes that the stacks would present a potential for bird collisions
- Increase impact to visual resources from the Sutter Refuge (based on input from the Sutter Refuge staff)
- Due to the close proximity to the Sutter Refuge, the plant may be inconsistent with the uses of the refuge
- There may be increased risk of flooding

Potential "Show-stoppers"

- The parcel is zoned agricultural and is under rice cultivation. A change of zoning is not believed to be possible under current county agricultural land use policy.
- Access and control of the property is believed to be infeasible as 66% ownership shares are unwilling to sell the property.
- If the plant is found to be in incompatible with the Sutter Refuge, it could not be permitted without a finding of over-riding consideration

ALTERNATIVES - Figure 4
Sutter Buttes Industrial Area Site and the O'Banion Road Site



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, NOVEMBER 1998
SOURCE: California Energy Commission Statewide Transmission Line and Power Plant Maps/1998 & USGS 7.5 Minute Quadrangles

Conclusion and Recommendation

CEQA requires the project alternatives analysis to focus on measures that would mitigate a project's potential significant environmental impacts to less than significant levels. The only significant environmental impact that was identified in the FSA/Draft EIS, that continues to be significant after mitigation, is a potential significant impact on visual resources. In our review of the four alternative sites, we believe that each site had the potential for significant visual impacts. In all cases (with the exception of the O'Banion Road site), these visual impacts were regarded as having a greater potential impact than that of the proposed SPP site. With regard to the O'Banion Road site, the visual resource impacts were less than for the SPP project site. However, the O'Banion Road site had three fatal flaws that could potentially cause the project to be denied.

Beyond the visual aspects of the alternative sites, each site encountered their own constraints, defects and potential fatal flaws which resulted in none of them being preferred over the SPP site. The project placed at any of the alternative sites would impact a greater number of residences and travelers along nearby roads with implications for greater impacts in the event of a hazardous materials incident, noise, traffic, land use conflicts and visual resources.

Considering all potential environmental impacts, public health and safety issues, and compliance with all laws, orders, regulations and standards, no alternative site was determined to be superior to the SPP site as each had impacts considered to be greater than that of the SPP project site. Therefore, in total, including visual resource impacts, the SPP site has fewer impacts than that of any of the alternative project sites reviewed.

add something?
"with exception of the O'Banion Rd. site"

DECLARATION OF

PAUL C. RICHINS, Jr.

I, Paul C. Richins, Jr., declare as follows:

1. I am presently employed by the California Energy Resources Conservation and Development Commission in the Facilities Siting and Environmental Protection Division as a Project Manager.

2. A copy of my professional qualifications and experience is attached.

3. I prepared the Alternative Analysis - Supplemental Testimony for the Sutter Power Plant Project based on my independent analysis of the Application for Certification and supplements hereto, data from reliable documents and sources, and my professional experience and knowledge.

4. It is my professional opinion that that portion of the prepared testimony is valid and accurate with respect to the issue(s) addressed therein.

5. I am personally familiar with the facts and conclusions related in that portion of the testimony and if called as a witness could testify competently thereto.

I declare under penalty of perjury that the foregoing is true and correct to the best of my knowledge and belief.

Dated: 11/24/98 Signed: Paul C R

At: Sacramento, California

Witness Qualifications
Paul Richins, Jr.

I have been employed by the California Energy Commission since 1985. I am currently working as the Energy Commission's Project Manager overseeing the environmental, engineering and public health and safety review of the Sutter Power Project.

Previously, I worked as a public policy advisor for three Commissioners over a 5 1/2 year span. As an advisor, I was involved in a wide variety of policy issues pertaining to: electric industry restructuring, research and development, energy efficiency, renewable generation resources and geothermal resources. I have been involved in the formulation of Commission policies in a wide range of areas including the major policy reports produced by the Commission: Electricity Report, Biennial Report, Energy Efficiency Report and the Energy Development Report. Additionally, I worked as an advisor to the Siting and Regulatory Procedures Committee and was involved in numerous electric generation issues addressed by the committee. I reviewed and made licensing recommendations regarding eleven electric generation siting cases heard by the Commission.

In addition, I worked for several years as a Program Manager with the responsibility for the work of a multi-disciplinary team of economists, engineers, environmental scientists and lawyers looking at future generation and transmission trends and issues under electric industry restructuring.

As a member of the El Dorado Hills Community Services District Board of Directors (1981-1990), I was instrumental in securing electric utility municipalization status for El Dorado Hills, successfully negotiated with PG&E to extend natural gas to all existing homes in the community, and secured 3 MW of ownership rights on the California-Oregon Transmission Project.

I hold a Bachelor of Arts degree from California State University--Sacramento in Economics.

TRANSMISSION SYSTEM ENGINEERING
TRANSMISSION SYSTEM ALTERNATIVES
Supplemental Testimony of Al McCuen

INTRODUCTION

The information provided below is in response to the hearing order dated November 13, 1998, requiring supplemental information to the Sutter Power Plant alternatives analysis contained in the Final Staff Assessment/Draft Environmental Impact Statement jointly filed by the Energy Commission and Western Area Power Administration staff on October 19, 1998. The hearing order required additional information on the alternatives being studied by the Sacramento Area Transmission Planning Group (SATPG) chaired by Western Area Power Administration. This ad hoc planning group has reviewed more than 20 alternatives over the past couple of years. This planning group was formed with the realization that if additional electrical supply is not provided to the Sacramento planning area, growth will be greatly restricted or there will be the imposition of voluntary load shedding, brownouts and eventually blackouts.

BACKGROUND

The Sacramento region has had a longstanding problem maintaining acceptable voltage levels and supporting load growth of the region. In 1996 the Sacramento Valley Study Group completed its report entitled the Sacramento Valley System Limitations Report. As a result of this report an undervoltage load shedding scheme to drop 400 Megawatts[1] of customers was implemented by the utilities in the Sacramento Valley to avert a system voltage collapse following a severe multiple-contingency disturbance (SATPG 1998b, page 5). A system voltage collapse can drop millions of customers off line for an extended period and result in millions of dollars of costs[2].

As a result of the Sacramento Valley Study Group report, the SATPG was formed to study long-term (10 years) transmission system reinforcements needed to support load growth and mitigate low voltages in the Sacramento Valley region. This planning group, of which Calpine and Western are members, is continuing to study system modifications and additions in order to maintain system reliability, voltage security, and load handling capability of the transmission system over the next ten years

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[1] The loads to be tripped are:SMUD (230 megawatts), PG&E (150 megawatts), and Roseville (20 megawatts).

[2] The August 10,1997 system outage impacted 11 western states, Canada and Mexico along with over 7 million customers This system disturbance resulted in 32,800 megawatts of lost load and 25,000 megawatts of lost generation. Industry losses are unknown but partial information indicates millions of dollars in losses. Losses in generation sales and the purchase of replacement power are unknown but the few losses that were documented are about 2 million dollars.

(Calpine 1997, AFC page 6-31, SATPG 1998b). This group has implemented short term mitigation measures to maintain adequate voltage for customers and are evaluating long term measures to meet load growth, eliminate the 400 megawatt load dropping measure, and conform with system reliability criteria.

Studies conducted by the SATPG and Western consider resources, loads, and transmission facilities in the western United States region and concentrate on the area generally between Redding/Oroville California and the area south to Tracy California (see Figure 1). Because of the interconnected nature of the Northern California system all generation resources, loads and major transmission/distribution facilities are analyzed. Additionally, it should be noted that the extreme distance (200-350 miles to Sacramento or San Francisco) between native hydroelectric generation in the north which combines with up to 4800 megawatts of Pacific Northwest power in the same location provides significant operating problems. This situation results in high voltages during light loading periods and very low voltages during peak loading periods. The addition of more transmission lines does not resolve the voltage problems; only local generating sources can fully mitigate the problem[3]. This type of problem occurs in several areas of California notably, Sacramento, San Francisco, and Humbolt County. The Cal-ISO is evaluating methods and financial incentives to encourage generating units to be sited near the load.

A new major transmission facility or generation facility requires from three to four years to become operational given planning, certification and construction timetables. For this reason planning analysis to maintain system reliability criteria and serve customers must be conducted in time to realize adequate service. The SATPG and Western local area and system reliability studies were conducted for the year 2003 with consideration of longer term load growth and system security[4]. Over the last summer there were 6 to 11 instances where electric power reserves approached or were at critical levels, ie. curtailable customers were dropped, and "no touch"[5] orders were issued by the Cal-ISO. IF PG&E and SMUD had not taken the preemptive action to drop load, the problem would have spread through the system.

Initial efforts to identify the Sacramento Valley needs considered about twenty 230 kV alternatives. Of these, four were considered feasible and were subjected to additional analysis. A summary of these conceptual alternatives, the SPP project and

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[3] While the SPP is 24 miles from the Elverta substation it is electrically very close and responds in a similar manner as it would if it were next to the Elverta substation.

[4] System security is a measure of maintenance of macro level system reliability, for instance preventing system cascading outages which may affect thousands or millions of customers by transferring "local" problems to other utility service areas and adjacent states.

[5] A curtailable customer is one which elects to be dropped off line and receives a reduced rate for being curtailed. If reducing load by dropping curtailable customers is not sufficient rolling blackouts could be utilized. A "no touch" day is one where maintenance of facilities is discontinued and those facilities are brought back on line and scheduled outages are delayed until the Cal-ISO issues a back in service order.

5-500 kV conceptual alternatives are shown in Transmission System Alternatives Table 1. (Attachment A provides a general overview of the Biological Resources that might be encountered along the various transmission line routes). The conceptual, general location of the alternatives is roughly shown on Figure 2[6]. Although these 230 kV alternatives could provide mediocre support to maintain voltage and reliability criteria, they are not sufficient for the long term needs of the Sacramento Valley area. Subsequent studies were conducted (circa August/September 1998) on five 500 kV alternatives in order to provide significant import of power into the area. In general, the area needs 500 to 1000 megawatts of additional generation and/or transmission imports to meet load growth and maintain system security[7].

It is very important for the reader to note that while increased transmission capacity can provide some power to the Sacramento Valley area, the "worth" of a megawatt of transmission import is nowhere as beneficial as a megawatt of local generation. While staff shows the comparison between megawatts of load growth for both transmission imports and the SPP generation they are not directly comparable. Importing power from Table Mountain for instance does not increase resources it merely redirects existing resources from one location to another.

Estimates of the load deficit in resources from Electricity Report 96 (Publication No. 300-97-001) for the area was 1034 megawatts for 2003. SMUD has recently indicated that the estimates used in the SATPG studies are already under estimated. It is important to note that while system studies for the Sacramento Valley area focus on the SMUD load and the performance of conceptual alternatives, the SMUD load is a surrogate that is used to identify the area's and system's performance. PG&E, Western, SMUD, Roseville, and NCPA are all affected by potential reliability deficits in the Sacramento Valley area. An example of this is the Yuba City area and Roseville area. Staff analysis for 1999 indicates line overloads north of the area on the extensive network of lines serving the area with an outage of the Calpine Greenleaf generation unit. PG&E is evaluating steps to mitigate such problems[8].

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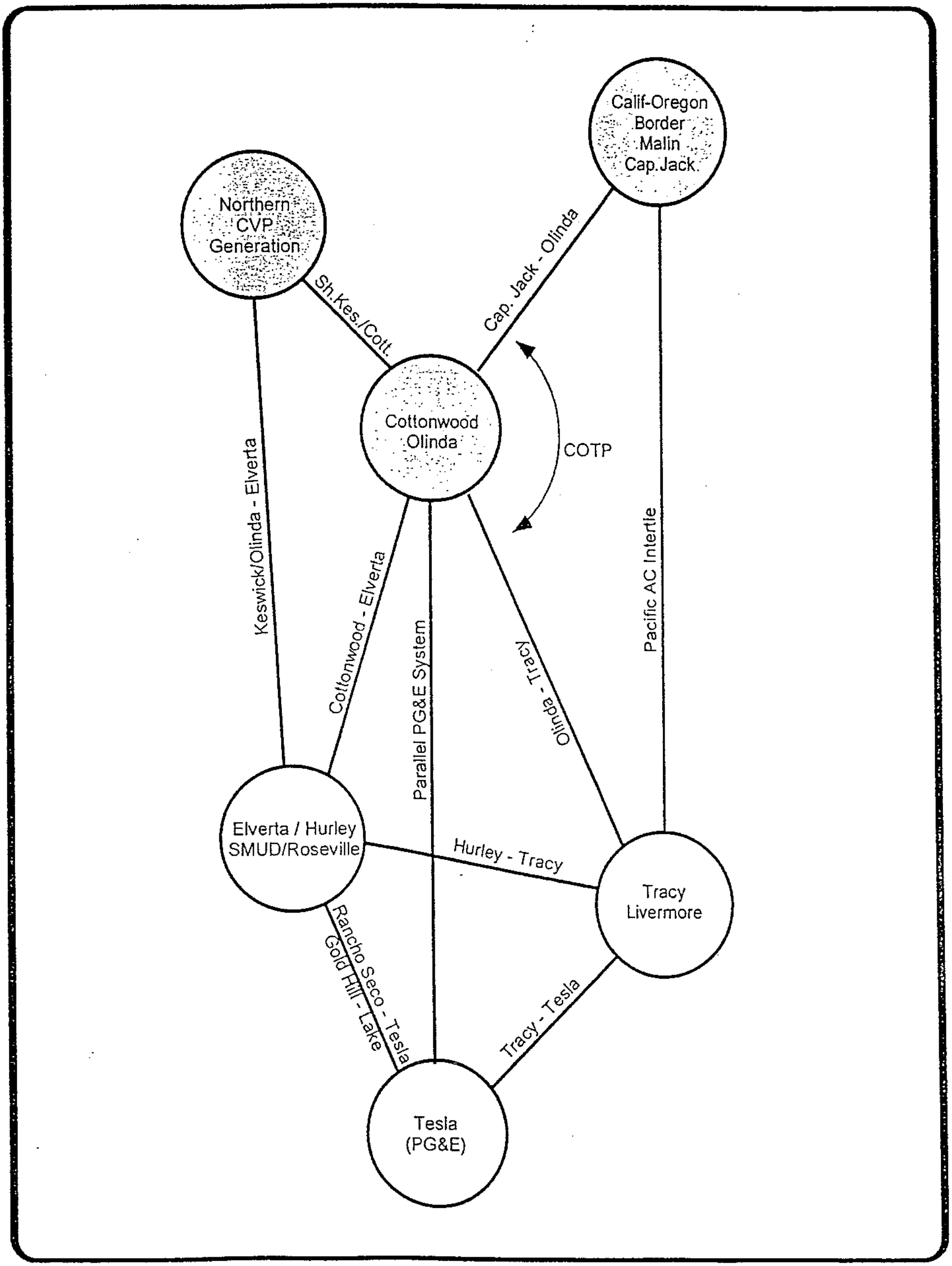
[6] No reconnaissance or screening studies of potential routes have been conducted. Staff generally placed rough locations adjacent to other lines approximately parallel where practicable.

[7] Stopgap (band aid) measures have been and were implemented as recent as this summer consisting of capacitors to attempt to maintain voltage levels.

[8] PG&E is also investigating a bidding process to provide incentives to a generating unit sponsor to locate in areas needful of generation.


Calif-Oregon Border Malin Cap.Jack
Northern CVP Generation
Sh.Kes./Cott.
Cap. Jack - Olinda
Cottonwood Olinda
COTP
Keswick/Olinda - Elverta
Cottonwood - Elverta
Parallel PG&E System
Olinda - Tracy
Pacific AC Intertie
Elverta / Hurley SMUD/Roseville
Hurley - Tracy
Tracy Livermore
Rancho Seco - Tesla
Gold Hill - Lake
Tracy - Tesla
Tesla (PG&E)

System Alternatives

Presently there are four conceptual 230 kV, and five 500 kV conceptual alternatives under study by the SATPG. The SPP project has also been evaluated. Except for the SPP, these alternatives are conceptual and very speculative at this time. There are no proponents or organizations proposing to finance and/or construct any of the conceptual alternatives. The transmission alternatives are not presently included in the utilities 5 year transmission plans.

Transmission System Engineering Table 1 summarizes the length, costs, increase in load in megawatts and the cost per megawatt of each alternative. As previously stated only very rough comparisons can be made between the generation alternative and transmission alternatives but are provided as a gross indication of performance. A megawatt delivered close to the load also provides reactive power, and is more "firm". A megawatt imported into an area is less firm, provides less reactive power and redistributes power; resources do not increase.

In Table 1, the "increase in load in megawatts" is a measure of the additional power provided to the system while maintaining voltage criteria; it is not the power plant output which is 525 megawatts maximum. Use of voltage criteria provides a uniform method of comparing alternatives not possible by simply comparing output power[9].

The Vaca-Dixon/Elk Grove, Tracy/Elk Grove, and Table Mountain/Elverta alternatives shown in Table 1 provide between 130 and 240 megawatts of load increase with costs ranging from $152,308 per megawatt to $40,000 per megawatt. The SATPG members consider these load increases inadequate because they are not sufficient for the anticipated load. The SPP would provide three to six years of load growth. The Sutter Bypass/Elverta alternative provides an additional 175 megawatt load increase at a cost of $34,857 per megawatt. Construction of this alternative would also provide sufficient additional capacity to meet a single line out criteria and disable the remedial action scheme used for the SPP[10]. The Elverta/Existing 500 kV alternative is a double circuit line which connects Elverta with the existing PG&E 500 kV Table Mountain to Tesla line. This alternative has fairly low per megawatt costs and provides 483 megawatts of load increase. The Table Mountain/Elverta alternative provides 450 megawatts of load increase at a cost of $1,142,857 per megawatt. The remaining 500 kV alternatives provide substantially less load increase.

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[9] Additional criteria evaluated by the SATPG members include voltage limits under single line out and double line out criteria. Critical points on the voltage profile were also evaluated.

[10] Because of potential overloads on the existing Western 230 kV lines a remedial action scheme would be used to maintain reliability. This scheme depending on loading of Western's lines could curtail 175 to 350 megawatts of SPP power.

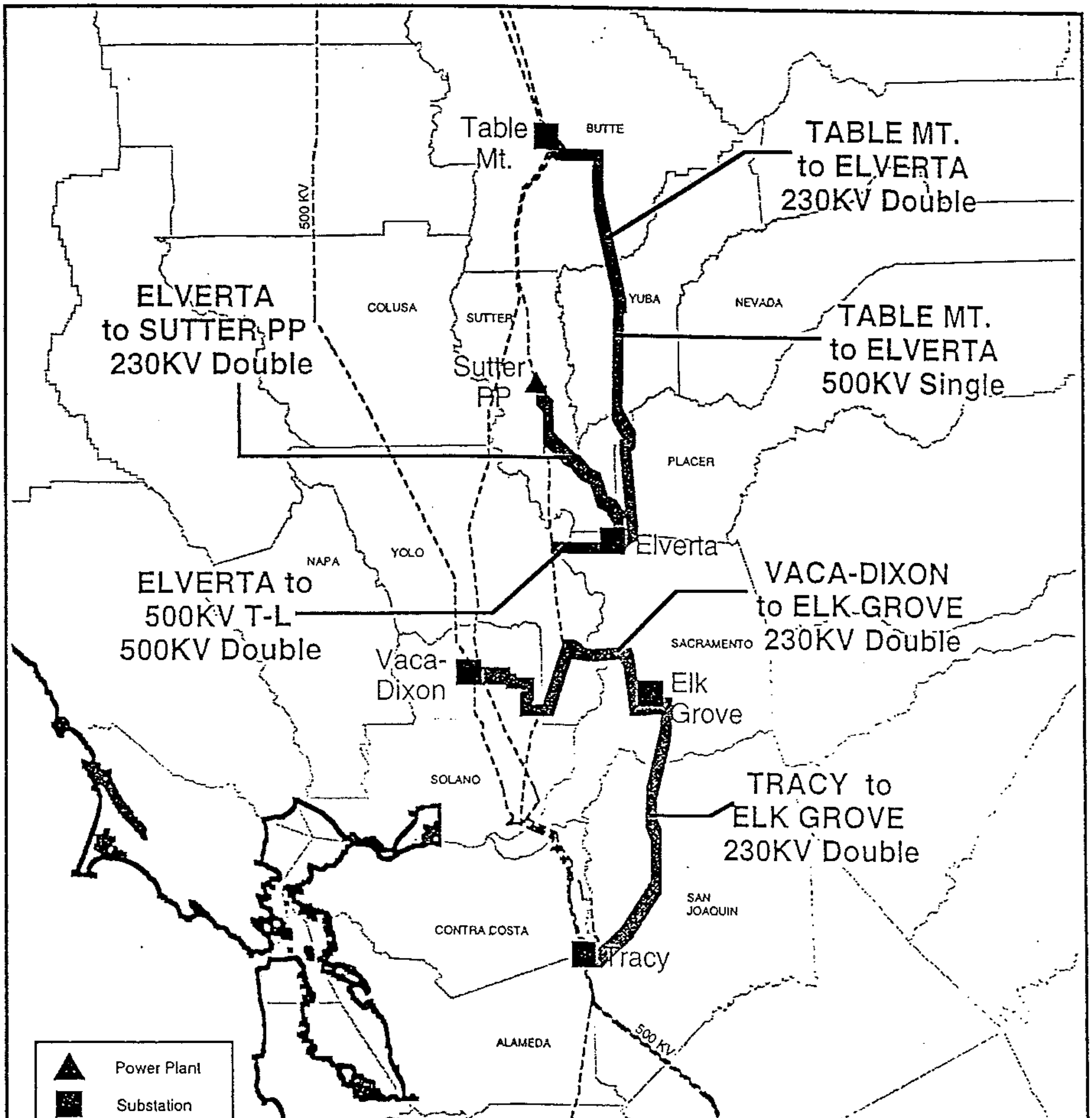
TRANSMISSION SYSTEM ALTERNATIVES
TABLE 1

Alternative	Increase in Load MW(1)	Length Miles	Cost(2) Millions $	Cost/MW(3)
No Project	----------	------	----------	---------
230 kV				
Vaca-Dixon/Elk Grove	240	32	9.6	40,000
Tracy/Elk Grove	170	40	11.7	68,824
Table Mt./Elverta	130	70	19.8	152,308
SPP Only	350	4	300	-------
SPP with Sutter Switching Station/Elverta line	175	23	6.1	34,857
500 kV				
Elverta/Existing 500 kV	483	10	19	39,337
Table Mt./Elverta	450	70	80	1,142,857
Elk Grove/Vaca Dixon	293	32	36	122,867
Elk Grove/Tracy	282	40	46	163,121
Rancho Seco/Tesla	214	50	57	266,355

(1) Megawatt increase in SMUD area load provided by alternative with all lines in service. Other system loads are accounted for also in the power flow analysis.
(2) 230 kV costs are based on SATPG Progress Report, Results of Phase I Screening Study, April 27, 1998. 500 kV costs are staff estimates based on Western's Conceptual Planning and Budget Cost Estimating Guide.
(3) Cost devided by megawatt load increase.

Source: SATPG Progress Report, April 27, 1998

Transmission System Engineering - Figure 2
Transmission System Alternatives



CALIFORNIA ENERGY COMMISSION, ENERGY FACILITIES SITING & ENVIRONMENTAL PROTECTION DIVISION, NOVEMBER 1998
SOURCE: California Energy Commission Statewide Transmission Line and Power Plant Maps/1998 & USGS 7.5 Minute Quadrangles

ATTACHMENT A

TRANSMISSION SYSTEMS ALTERNATIVES
Biological Resources
Supplemental Testimony of Linda Spiegel

The information provided herein relates to biological resources along transmission system alternatives. Ten transmission system alternatives have been identified, five 230 kv and five 500 kv lines, representing seven routes. (three routes have both 230 kv and 500 kv as an alternative; see Transmission System Engineering Table 1, Transmission System Alternatives). One alternative is the SPP proposed route without the extension to Elverta, which is discussed in the FSA . One alternative, Tesla to Rancho Seco, was determined impractical due to poor performance (low load increase). This section addresses the five remaining routes:

SPP to Elverta;
Table Mountain to Elverta;
Elverta to an existing 500 kv line east of Woodland;
Elk Grove to Vaca Dixon, and;
Elk Grove to Tracy.

This report is based on information provided in the California Natural Diversity Data Base (CNDDB) and staff's knowledge of the potential sensitive biological resources that could occur along the five alternative routes. No reconnaissance or screening studies of these potential routes have been conducted by CEC's transmission system staff. Staff generally placed rough locations adjacent to existing lines. Due to time constraints, an in-depth analysis of biological resources was not conducted and the five alternative routes were not visited by staff. Instead, maps of the routes were reviewed and areas with the potential to contain sensitive biological resources were noted. In addition, the CNDDB data were not used to compare the biological resources between routes, but as a general reference for what resources are known to occur on each route.

The types of biological resources considered most important are wetlands, riparian areas, listed birds, waterfowl and other water-related birds, as these are most susceptible to long-term impacts from the existence of transmission lines. Waterfowl and water-related birds, such as herons and cranes, are susceptible to collisions with the conductors, particularly the topmost, small diameter shield wire. Wetlands and riparian areas attract waterfowl and water-related birds. Listed birds have diminished numbers and the loss of individuals have greater consequences to the population. Birds considered were those most susceptible to collisions due to behaviors. Other consideration was given to oak woodlands and vernal pools, both sensitive habitats.

Biological Resources Table 1 provides a comparison of the five transmission line routes in relation to the presence of relevant biological resources. Each of the

Biological Resources Table 1: A Comparison of relevant biological resources along five alternative transmission systems. An "x" equals resource likely present, a "+" equals resource relatively more abundant

	Table Mtn /Elverta	SPP/Elvert a	Elverta / Woodland	Elk Grove/ Vaca Dixon	Elk Grove/ Tracy
Length (mi)	70	23	10	32	40
Wetlands	x	x	+	+	x
Riparian	+	x	x	+	+
Vernal Pool	+	x	x	+	+
Oak Woodland	+	x	x	x	+
Waterfowl	x	+	+	+	x
Water birds	+	+	+	+	+
Sandhill Crane	x	+	+	+	x
Peregrine Falcon	+	+	+	+	+
Bald Eagle	+	+	+	+	x
Golden Eagle	+	x	x	x	+
Swainson's Hawk	+	+	+	+	+
Avian Collision	x	+	+	+	x

resources listed in Table 1 are present along each line. However, after a cursory review, it appears that some resources would be more prevalent along some lines than along others.

Table Mountain to Elverta:

This route is approximately 70 miles long, traveling north-south from just northwest of Oroville in Butte County to Elverta in Sacramento County. The route crosses numerous small creeks and three large waterways - South Honcut Creek, Yuba River, and Bear River. The route travels through oak woodland habitats, several rice fields and other crops, and will likely cross vernal pool habitat. Water bird use is likely high, but water fowl use is probably lower than routes traveling through the valley proper. Bald eagles may use Lake Oroville and the Thermalito Afterbay for both winter roosting and nesting. Golden eagles may use the foothill habitat for nesting. Swainson's hawks and peregrine falcons will occur seasonally, and Swainson's hawk nesting habitat is available along the southern portion of the route. The risk of avian collision may be high along the waterways and rice fields, but lower than other proposed routes.

Sutter Power Plant to Elverta:

This 23-mile route would be along the Sutter Bypass, cross the Feather River and continue south by southwest to Elverta. The route parallels riparian habitat and rice fields, and will transverse the Pacific Flyway. Some wetland and vernal pool habitat may be present near Elverta. Swainson's hawks will occur during the spring and summer months, and bald eagle and peregrine falcons will occur in low numbers during the winter months. Waterfowl and water bird use will be relatively high, thus the risk for avian collision would be high.

Elverta to an Existing 500 kv Line East of Woodland:

Because this east-west route is relatively short (10 miles), fewer resources are present than in projects involving longer routes. However, the route is within the Pacific Flyway, is almost entirely in rice field or wetland habitat, and crosses the Sacramento River and the Yolo Bypass. Therefore, the risk for avian collision is high. Bald eagle, peregrine falcon, and Swainson's hawk will be seasonally present.

Elk Grove to Vaca Dixon:

This 32-mile route travels east-west from Elk Grove over wetlands, the Sacramento River, Yolo Bypass, and through grain and pasture fields, and possibly some vernal pools, to Vaca Dixon. The risk of avian collision will be high through the wetlands and Yolo Bypass. Sandhill cranes will use the grain fields as foraging habitat. Bald eagle, peregrine falcon, and Swainson's hawks will be seasonally present. The area also receives high use by wintering raptors, including red-tailed hawks, rough-legged hawks, and ferruginous hawks.

Elk Grove to Tracy:

This route runs south to Stockton then south by south west to the Clifton Court Forebay. This 40-mile route crosses wetlands, the Cosumnes River, Dry Creek, and possibly several waterways associated with the Delta. Waterfowl collision is probably lower along this line because it crosses fewer areas managed for waterfowl. However, sandhill cranes winter along the Cosumnes River and in the grain fields south to Stockton, and water birds will occur in the waterways along this route. Golden eagles may nest in the foothills near Tracy. Peregrine falcons, bald eagles, and winter raptors will occur seasonally. Vernal pool habitat may be encountered from Elk Grove to Stockton.

SOCIOECONOMICS
Testimony of Amanda Stennick and Gary D. Walker

Through the Committee Order, in regard to Socioeconomics, staff was asked to do further analysis of the SPP on the following issues:

1) the impact of the SPP on the local agricultural economy; and

2) the impact of the project on the value of property in the area.

In the supplemental testimony, staff was asked to address these points and include factors such as the potential for diminution of property values, increased costs to growers, and reduction in agricultural yield which may be caused by the project and its ancillary facilities. Staff was further directed to specify appropriate mitigation measures and / or available alternatives should the resulting analysis of the economic impacts to the agricultural economy and / or property values conclude that there is a significant quantifiable impact.

ANALYSIS

Impacts on the Local Agricultural Economy

To address the impact of the SPP on the local agricultural economy, staff has done the following:

Staff calculated the acreage that would be lost due to the SPP project. The 77-acre SPP parcel would not be lost to production because it has been out of production since 1986.

Staff then estimated the acreage that would be lost to production due to the proposed transmission line. Staff used the worst-case assumption that the proposed transmission line would remove all land within a 125 foot right-of-way from production.[1] Based on a 4.0 mile proposed transmission line, the acreage lost would be 61 acres. Staff did not use the approach of quantifying the precise acreage that would be lost due to particular project elements such as the switching station and pole foundations. This approach was not used because it would not capture all farming costs and reductions in crop yields. These include increased costs due to additional cultivating efforts and aerial applications. Therefore this approach would not meet requirement in the Committee's order that staff consider increased costs to growers and reduction in agricultural yield.

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[1] In fact, much of the transmission right-of-way may be located outside cultivated areas. Even where the land is undercultivation, it may (and probably will) remain so, but at increased cost or with decreased yields were the line not built.

Staff then calculated the loss in crop production value due to the proposed transmission line. To do this, staff used the acreage losses cited above and rice production data in the Sutter County 1997 Crop Report. Staff multiplied acreage lost by production per acre (in tons), then multiplied by the value per ton. The resulting loss in crop production value is $42,137 for 1997. To put this figure into context, the 1997 gross value of agricultural production in Sutter County was $277,169,700, according to the Crop Report. This loss in crop production represents .015 percent of the County's rice production for 1997.

Staff also contacted the UC Davis Agricultural Extension Office, who directed staff to Dr. George Goldman at the UC Berkeley Agricultural Extension Office. Staff provided Dr. Goldman with the figures on the value of lost production due to the SPP project. Dr. Goldman used the IMPLAN input-output model to calculate the reduction in production output and income.

Based on Dr. Goldman's results, staff calculated the reductions in output and income from the SPP transmission line. The estimate of $42,137 reduction in production value for the proposed transmission line results in an output reduction of $69,526 for 1997 and an income reduction of $35,247 for 1997. Staff's conversation with Dr. Goldman indicated that the results of the model represent broad market values, and are not landowner or parcel specific. Staff told Dr. Goldman that staff had been directed to address increased cost to growers and reduction in agricultural yield which may be caused by the project and transmission line. He said that local agricultural experts would have to be consulted to determine any change in production costs or yields for affected growers, and that this information would have to be further evaluated by an agricultural economist.

Impacts on Property Values in the Area

Staff took several steps to address the impact of the project on the value of property in the area. First, staff made a number of phone calls to the Sutter County Assessor's Office to determine how agricultural land is assessed, under what circumstances this land would be assessed at a lower value, and how this would diminish property values of the land assessed. The phone calls were not returned. Staff also contacted a Sutter County appraiser who was not available in the time requirements necessary to respond to the Committee Order.

In addition, staff attempted to evaluate the change in property values in the vicinity of the existing Greenleaf 1 project as an indication of the potential effect of the proposed project on property values in the area. Staff sought data from the Sutter County Assessor's Office regarding property sales before and after the construction of Greenleaf 1. Staff procured parcel maps and sales data for properties in the vicinity of the project site.[2] The data indicate that 14 parcels were sold between 1976 and 1996 (see Attachment A). Of this number, five parcels were sold as parts of larger sales, so price data is not available for the specific parcels. Of the nine remaining parcels, four were sold before construction of Greenleaf 1 and have not been sold since then. The five parcels sold after construction of Greenleaf 1 were not sold in the period from 1976 to the construction of Greenleaf 1. Therefore, no comparison between land values before and after construction of Greenleaf 1 is possible from this data.

CONCLUSIONS AND RECOMMENDATIONS

In regard to effects on the local agricultural economy, staff finds that the SPP and its related facilities will not have a significant quantifiable impact on the local agricultural economy because the reduction in crop production value will be a tiny fraction of the gross value of agricultural production in Sutter County. In addition, the reductions in output and income as calculated using Dr. Goldman's input-output model are small. Therefore, staff does not recommend any mitigation measures in regard to this issue.

In regard to effects on the value of property in the area, in the time available staff was not able to determine whether the project will have a significant quantifiable impact on the value of property in the area. Therefore, staff does not recommend mitigation measures in regard to this issue.

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[2]Sutter County provided the data according to parcel use codes. The two codes related to agriculture are "open land," including rice fields, and "orchards." Because the data concerning orchards contained several variables (such as the species of tree and the age of orchards) that varied over time and would have an effect on land values that staff could not calculate, parcels with orchards were not evaluated further. Staff instead focused on parcels designated as "open land," including rice fields. Staff identified the parcels in the vicinity that had sales data between 1976 and 1996 (the latest year for which sales data by crop type are available).

ATTACHMENT A
- PARCELS IN THE VICINITY OF GREENLEAF 1
- SALES 1976 TO 1996

PARCEL NO.	SALE DATE	PRICE (sold before Greenleaf 1)	PRICE (sold after Greenleaf 1)	ACREAGE
21-240-043	04/91		480000.00	240.00
21-230-014	01/92		120000.00	38.00
21-240-040	02/92		185000.00	74.25
21-240-039	03\92		170000.00	74.25
21-240-038*	10\96			335.02
24-070-008*	10\96			81.79
24-070-012*	10\96			82.26
21-240-048*	12\92			267.42
24-070-015*	12\92			163.46
21-230-022	06\94		356500.00	155.00
21-240-012	04\82	500000.00		155.00
21-240-006	06\80	418700.00		158.00
21-240-022	10\80	3000000.00		479.00
21-240-006	12\80	513500.00		158.00

*These parcels were sold as parts of larger sales, so prices per parcel are not available.

PLANT CLOSURE

Supplemental Testimony of Steve Munro

This supplemental testimony is in response to the Sutter Power Project Siting Committee's request, in its Notice of Evidentiary Hearings signed on November 13, 1998, to provide information to explain why the Facility Closure section of the Final Staff Analysis (FSA) for the Sutter Power Project does not require a plant closure fund.

BACKGROUND

As a condition of certification, staff has required all power plant project owners to submit proposed closure plans at least 12 months prior to the anticipated cessation of operations. A closure plan is not required during the certification process because of a number of difficulties and uncertainties in trying to predict appropriate closure measures 30 years or so in advance (see the analysis section of this testimony for more detail). The proposed closure plan is subject to a public review process similar to the AFC process that results in a final approved closure plan, and additional closure conditions, if necessary, to protect the environment and public health and safety. In addition to planned closure, project owners must be prepared to deal with unforeseen closure, either permanent or temporary, in a safe and environmentally responsible manner. This is required by the proposed conditions of certification. In developing these conditions, staff evaluates power plant applications to determine if a plant closure fund is needed as a condition of certification in order to guarantee protection of public health and safety and the environment.

Historically, closure fund requirements have been included as a condition of certification only when there is a compelling reason, such as:

1. A known history of financial irresponsibility of the project applicant in previous projects or dealings casting doubt on the willingness or ability to pay closure costs;

2. Quantities or types of hazardous materials stored, or disposed of, on the project site which are out of the ordinary in terms of potential impacts. In the event of a sudden unexpected closure or prolonged interruption of operations, removal and securing of these materials would require immediate action, involving unusual expense, which would be covered by the closure fund.

A closure fund was required for one previously Commission-certified power plant, the SEGS VIII Solar-Electric Generation Station project. The compelling reason was to ensure prompt, safe storage and removal of an unusually large quantity of a hazardous petrochemical liquid used as a heat transfer fluid in the solar-electric generation field. The closure fund requirement in the SEGS VIII project was relatively small and covered only the immediate cost of site security, maintenance and hazardous materials storage and removal.

Electric industry deregulation has resulted in less certainty with regards to the future status of certified power plants, including operational characteristics, ownership and financial conditions. Therefore, the ability of staff to conclude whether or not compelling need exists for plant closure funds is difficult. This issue will be important for all power plants coming before the Commission now, and in the foreseeable future. Staff believes that the Commission's electricity policy forum is the most appropriate mechanism for addressing this issue. It would enable the Commission, other governmental agencies, and all interested parties, public and private, to participate in evaluating the need and financial mechanisms for closure funds, and the implications closure funds would have for power plant development in a deregulated industry. Issues such as the need for regulations, legislation, and calculation of the extent of closure funding required could also appropriately be addressed in this forum (see Attachment A., "Response of Commission Staff to Committee Scheduling Order," docket date Feb. 27, 1998, for the High Desert Power Project (the first six pages are provided).

ANALYSIS

CALPINE addressed facility closure in Section 4 of the AFC and included a discussion of the measures that they would implement to handle temporary or permanent facility closure. The plans which CALPINE described demonstrate a clear understanding of the contingencies, issues, security measures and other steps necessary to remedy and prevent environmental hazards and protect worker and public health and safety, and the clear commitment to carry them out. There are no known reasons to assume that CALPINE does not, or will not have the financial resources necessary to carry out any reasonably anticipated closure measures at the time the facility ceases operation. In addition, if CALPINE sold the project, a publicly-noticed amendment petition would be required. Any subsequent owner would have to demonstrate to the Commission a willingness to carry out all conditions of certification, including closure conditions and requirements. The transfer of ownership would not be approved if the prospective new owner could not demonstrate this commitment.

Staff examined facility closure issues, including costs, as part of their analyses in each technical area and recommended facility closure conditions in the Facility Closure section of the FSA. They found these closure issues did not necessitate a dedicated facility closure fund.

As discussed in the background portion of this testimony, the following uncertainties greatly complicate the identification of specific closure measures and costs at this time:

1. It is not known what the characteristics of the environs surrounding the facility will be in 30 or so years when the facility is closed. Those characteristics will have a major bearing on what specific closure measures and mitigation will be necessary to prevent a significant environmental impact when the project ceases operation.

2. Although current LORS are known, it is not known what specific changes and new LORS will be in place at the time of closure.

3. It is not known at this time what the conversion or salvage value of the project structures and equipment will be at the time of closure. This prevents determination of the net removal, dismantling, and other closure costs.

The assumption that the Sutter Power Project may retain significant value at the time of closure is supported by recent closure experience involving a project under the Commission's jurisdiction. The net closure costs in that case, after recuperating salvage value and revenue from the sale of land, equipment, and other assets, have been relatively low. In addition, the recent divestiture of assets by utility companies in California has demonstrated that power plant equipment and assets retain a significant market value even after 40 years or more.

As discussed in the Background section, the above-cited variables cannot be known until the proximate time of closure. That is why the Facility Closure section specifies that 12 months prior to the anticipated cessation of operation of the project, a proposed closure plan must be submitted and a public review process initiated. This process will be essentially equivalent to the AFC process, and will be used to develop a specific closure plan, necessary mitigation measures, and additional closure conditions, if necessary, to prevent any significant impacts to the environment and public health and safety. The process will involve the Commission, the staff, other interested state, federal and local agencies, and members of the public. It is only through this process that the net costs of project closure will be reliably identified. The Commission must approve the final closure plan and conditions.

CONCLUSION

Staff does not believe that a facility closure fund is necessary to ensure that facility closure requirements contained in the proposed conditions of certification will be carried out by the applicant. Staff believes that the proposed facility closure conditions of certification will prevent significant environmental, health, and safety impacts at the time of project closure under reasonable foreseeable circumstances.