C. Davis

BAY AREA
AIR QUALITY
MANAGEMENT
DISTRICT

February 6, 2001

Mr. Gerado C. Rios
Acting Supervisor, Permits Office Air Division
United States Environmental Protection Agency
75 Hawthorne Street
San Francisco, CA 94105-3901

Dear Mr. Rios:

The District appreciates EPA's comments on the Contra Costa Power Plant PDOC.

We would like to respond to each specific comment to show how we have addressed it in the FDOC a copy of which is attached. Before addressing specific comments, however, a general response might be helpful.

The limitations contained in other preconstruction permits are not relevant to a BACT/LAER determination. These levels represent the unrealized hopes of the applicant and the unproven claims of the vendor. They become relevant only when the equipment has been constructed and operated in compliance with the limit for six months or more. At that point, the new limit has been "achieved in practice".

The second general comment is that SCONOx and XONON are promising but, as yet, unproven technologies in units like Contra Costa Power's. The feasibility of successful scale-up from the 32 MW Federal prototype has not yet been demonstrated in a commercial unit. We are not even completely convinced that the Federal unit constitutes successful commercial demonstration of the technology; we have no information concerning the amount of attention required to keep the unit operating properly.

The District has consistently considered SCONOx in its BACT review for every large combined cycle turbine proposed in the last year, and every time has determined that the technology is not yet proven.

Specific Comments:

(1) CO BACT determination.
District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for CO as 6 ppmvd, @ 15% O_2 with an averaging period of one hour.

This BACT determination was based upon the use of CO Catalyst and Dry Low NO_x combustors. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O_2, it established the technologically feasible/cost-effective BACT specification cited above.
However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% O_2 under all loads and ambient conditions with and without duct burner firing, with one exception. Crockett does not expect to consistently meet 10 ppmvd CO, when operating in steam injection power augmentation mode.

None of the three power plants recently permitted in the Bay Area expressed any problem being limited to 10 ppmvd CO, even during steam injection power augmentation mode. All have agreed to operate below 10 ppmvd during all modes of operation, except during start-up and shutdown. Two of the power plants have further agreed to operate below 6 ppmvd during all modes of operation, except during start-up and shutdown. We expect the use of newer low-NOx combustors and oxidizing catalysts to consistently meet 10 ppmvd CO, except during start-up and shutdown.

Therefore, achieved in practice BACT2 for CO is deemed to be 10 ppmvd CO @ 15% O_2 for the combined exhaust from the gas turbine/HRSG duct burners during all modes of operation, except during gas turbine start-up and shutdown. The applicant will typically comply with this BACT specification through the use of dry low-NO_x combustors, which minimize incomplete combustion and/or through the use of an oxidation catalyst.

Two power plants in the Bay Area were recently issued permits with a CO emission concentration limit of 6.0 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because the power plants proposed this limit, it was accepted as meeting BACT 1 for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated in actual operation. The 6.0 ppmvd will be considered BACT 1 "technologically feasible/cost-effective BACT" for CO emissions.

The CCPP Unit 8 has agreed to a CO emission limit of 6 ppmvd @ 15% O_2 that will apply to all gas turbine/HRSG operating modes except for gas turbine start-up and shutdown. As is the case for Los Medanos Energy Center, this limit will apply to the firing of the turbine alone, turbine operation with HRSG duct burner firing, and steam injection power augmentation mode. The CCPP Unit 8 intends to comply with this BACT specification through the use of dry low-NO_x duct burners, which minimize incomplete combustion, and by the use of a CO oxidation catalyst. The applicant's proposed CO level of 6 ppm therefor complies with BACT.

(2) VOC BACT Determination.
The basis for the District's VOC BACT determination is the same as for CO. The District is unaware of any commercial installations consistently operating at POC levels < 2 ppm while meeting a NOx level of 2.5 ppm.

(3) Ammonia Slip Limit.
The basis for the proposed ammonia slip requirement is the same as for CO. The District considers vendor guarantees as support for an applicant's request to base emission calculations on lower emission rates than have been reliably achieved; it does not, however, consider them adequate justification for imposition of more stringent levels.

However, in response to PDOC comments and in view of other power generation projects recently approved, the applicant has agreed to comply with an ammonia slip limit of 5 ppmvd at 15% O_2. The appropriate permit conditions in the FDOC have been revised to reflect this change.

(4) Adequacy of Discussion of BACT Determination.
The additional explanation has been added to the FDOC.

The District does <u>not</u> select control technology. The District sets target emission rates, based upon the most advanced control techniques that have been successfully applied. The applicant must meet or exceed these levels using any technique available.

The BACT discussion has been expanded in the FDOC to make the basis for the District's decision clear.

(5) NOx limits contained in permits for unconstructed sources are not relevant to the District's BACT determination. We would welcome EPA's assistance in identifying any comparable facility that has consistently achieved NOx levels of 2.0 ppm or less.

(6) Environmental Impacts of Alternative Controls.
As has been discussed, the District has determined that of SCONOx and XONON are unproven in this service. They were eliminated from consideration on this basis.
As they are not viable alternatives, any discussion of possible "benefits" from their use would be speculative.

(7) MACT Discussion.
A discussion of the MACT requirements, as they apply to this application, has been added to the FDOC.

(8) Surplus Nature of Offsets.
All offsets utilized in the District are surplus at the time of use. The requested discussion is unnecessary.

(9) Use of Pre-1990 Offsets.
No response required.

(10) PSD Air Quality Analysis.
The air quality impact analysis in Appendix E of the PDOC addresses all requirements of PSD regulation 40 CFR 52.21. A PSD increment analysis is only required for a facility where the air quality impacts exceed EPA specified impact significance levels. The air quality impacts from the proposed facility are all below the pollutant specific significance levels. Therefore a PSD impact analysis was not required for the proposed facility.

(11) Compliance Monitoring for VOC and PM-10.
The permit will be modified to require appropriate monitoring requirements for VOC and PM-10.

(12) RATA test Requirements.
We plan to include pinpoint citations in the Major Facility Review Permit. We do not explicitly include the requirements in PSD permits.

(13) ESA Consultation.
We understand that the PSD permit may not be issued until EPA has confirmed that the requirements of the ESA have been satisfied.

Sincerely,

Ellen Garvey
Executive Officer/
Air Pollution Control Officer

EG:frw

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P.O. Box 249, Antioch, CA 94509

Final
Determination of Compliance

Contra Costa Power Plant
Unit 8 Project

Bay Area Air Quality Management District
Application 1000

February 2, 2001

Dick Wocasek, P.E.
Air Quality Engineer

Contents

List of Tables

Table		**Page**

I Introduction

This is the Preliminary Determination of Compliance (PDOC) for the Unit 8 Project at the existing Contra Costa Power Plant (CCPP), a 530-MW, natural-gas fired, combined cycle merchant power plant proposed by Southern Energy California. The existing power plant is located about 1-mile northeast of the city of Antioch on Wilbur Avenue near State Route (SR) 4, SR 160 and the Antioch Bridge. The new unit will include two natural gas fired General Electric Frame 7FA combustion turbine generators (CTGs), one steam turbine generator and associated equipment, two supplementally fired heat recovery steam generators (HRSGs) and a wet cooling tower.

A. Background

Pursuant to BAAQMD Regulation 2, Rule 3, Section 403, this document serves as the Preliminary Determination of Compliance (PDOC) document for the CCPP Unit 8. It will also serve as the evaluation report for the BAAQMD Authority to Construct application #1000. The PDOC describes how the proposed facility will comply with applicable federal, state, and BAAQMD regulations, including the Best Available Control Technology and emission offset requirements of the District New Source Review regulation. Permit conditions necessary to insure compliance with applicable rules and regulations and air pollutant emission calculations are also included. This document includes a health risk assessment that estimates the impact of the project emissions on public health and a PSD air quality impact analysis, which shows that the project will not interfere with the attainment or maintenance of applicable ambient air quality standards.

Pursuant to Regulation 2, Rule 3, Section 404, this PDOC is subject to the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407.

B. Project Description

1. Process Equipment

The applicant is proposing a combined-cycle cogeneration facility with a maximum electrical output of 530 MW. The CCPP Unit 8 will consist of the following new permitted equipment:

S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-NO_x Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-NO_x Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.

S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute

As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 175 MW and the steam produced by both heat recovery steam generators (HRSGs) will feed to a single steam turbine generator with a nominal electrical output of 192 MW.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

As a merchant power plant, market circumstances and demand will dictate the exact operation of the new gas turbine/HRSG power trains. However, the following general operating modes are projected to occur:

Base Load: Maximum continuous output with duct firing and power augmentation steam injection during high ambient temperature conditions

Load Following: Facility would be operated to meet contractual load and spot sale demand, with a total output less than the base load scenario

Partial Shutdown: Based upon contractual load and spot sale demand, it may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during period of low overall demand such as late evening and early morning hours

Full Shutdown: May be caused by equipment malfunction, fuel supply interruption, or transmission line disconnect or if market price of electricity falls below cost of generation

HRSG Duct Burner Firing with Steam Injection Power Augmentation:

Under peak demand situations and high ambient temperatures, steam may be injected into the gas turbine combustors to lower the flame temperature and allow increased fuel use rate, which results in increased mass flow through the gas turbine thereby increasing maximum electrical output.

The following projected operating scenario was utilized to estimate maximum annual air pollutant emissions from the new gas turbines and HRSGs.

- 4304 hours of baseload (100% load) operation per year for each gas turbine @ 60°F
- 4313 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 83 gas turbine hot start-ups per year (90 min. each)
- 28 gas turbine cold start-ups per year (256 min. each)
- 111 gas turbine shutdowns per year (23 min. each)

3. Air Pollution Control Strategies and Equipment

The proposed CCPP Unit 8 includes sources that trigger the Best Available Control Technology (BACT) requirement of New Source Review (District Regulation 2, Rule 2, NSR) for emissions of nitrogen oxides (NO_x), carbon monoxide (CO), precursor organic compounds (POCs), sulfur dioxide (SO_2), and particulate matter of less than 10 microns in diameter (PM_{10}).

a. Selective Catalytic Reduction with Ammonia Injection for the Control of NO_x

The gas turbines and HRSG duct burners each trigger BACT for NO_x emissions. The gas turbines will be equipped with dry low-NO_x (DLN) combustors, which are designed to minimize NO_x emissions. The HRSGs will be equipped with low-NO_x duct burners, which are designed to minimize NO_x emissions. In addition, the combined NO_x emissions from the gas turbines and HRSGs will be further reduced through the use of selective catalytic reduction (SCR) systems with ammonia injection. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level NO_x emission limit of 2.5 ppmvd @ 15 % O_2 (one hour average).

b. Dry Low-NO_x (DLN) Combustors and Oxidation Catalyst to Minimize CO Emissions

The gas turbines and HRSG duct burners each trigger BACT for CO emissions. The gas turbines will be equipped with dry low-NO_x combustors, which are also designed to minimize CO emissions. The HRSGs will be equipped with a CO catalyst designed to catalytically oxidize the CO and POC produced from firing natural gas in the CT and duct burner. The gas turbine and HRSG duct burner combined exhaust will achieve a BACT-level CO emission limit of 6.0 ppmvd @ 15 % O_2 and a POC level of 2.0 ppmvd @ 15 % O_2.

c. Dry Low-NO_x (DLN) Combustors and the CO catalyst to minimize POC Emissions

The Gas Turbines and HRSGs each trigger BACT for POC emissions. The gas turbines will utilize dry low-NO_x combustors, which are designed to minimize incomplete combustion and therefore minimize POC emissions. The HRSGs will be equipped with a CO catalyst to minimize CO and POC emissions.

d. Exclusive Use of Clean-burning Natural gas to Minimize SO_2 and PM_{10} Emissions

The gas turbines and HRSG duct burners will utilize exclusively natural gas as a fuel to minimize SO_2 and PM_{10} emissions. Because the emission rate of SO_2 depends on the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics; the use of natural gas will result in the lowest possible emission of SO_2. PM_{10} emissions are minimized through the use of best combustion practices and "clean burning" natural gas.

II Facility Emissions

The facility regulated air pollutant emissions and toxic air contaminant emissions are presented in the following tables. Detailed emission calculations, including the derivations of emission factors are presented in the appendices.

Table 1 is a summary of the daily maximum regulated air pollutant emissions for the gas turbines, heat recovery steam generators (HRSGs) and cooling tower. These emission rates are used to determine if the Best Available Control Technology (BACT) requirement of the District New Source Review Regulation (NSR; Regulation 2, Rule 2) is triggered on a pollutant-specific basis. Pursuant to Regulation 2-2-301.1, any new source that will result in POC, NPOC, NO_x, SO_2, PM_{10}, or CO emissions in excess of 10 pounds per highest day per pollutant are subject to the BACT requirement for that pollutant.

Table 1 Maximum Daily Regulated Air Pollutant Emissions for Baseload Operation of Proposed Sources[a] (lb./day)

Pollutant	Source			
	S-41 CTG & S-42 HRSG[a]	S-43 CTG & S-44 HRSG[a]	S-45 Fuel Preheater[b]	S-46 Cooling Tower
Nitrogen Oxides (as NO_2)	997	997	7.2	
Carbon Monoxide	1801	1801	2.4	
Precursor Organic Compounds	234	234	3.0	
Particulate Matter (PM_{10})	312	312	1.4	43
Sulfur Dioxide	148	148	0.5	

[a]Based upon one cold start, one hot start, 16 hours of CTG/HRSG baseload operation with HRSG firing and steam injection power augmentation and 2.2 hours of CTG/HRSG baseload operation in a 24-hour period.

[b] The Fuel Preheater is operated only during starts. Operation limited to 16 hours/day.

Table 2 is a summary of the maximum facility toxic air contaminant (TAC) emissions from new sources. These emissions are used as input data for air pollutant dispersion models used to assess the increased health risk to the public resulting from the project. The ammonia emissions shown are based upon a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the A-11 and A-13 SCR Systems.

Table 2
Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb./yr-source)
S-41, S-42, S-43, and S-44 Combined		
Acetaldehyde[b]	2558	72
Acrolein	884	3.9
Ammonia[c]	518,242	19,300
Benzene[b]	506	6.7
1,3-Butadiene[b]	4	1.1
Ethylbenzene	670	193,000
Formaldehyde[b]	4102	33
Hexane	20,000	83,000
Naphthalene	62	270
PAHs[b]	38	0.043
Propylene	39,214	none specified
Propylene Oxide[b]	1780	52
Toluene	2706	38,600
Xylenes	1078	57,900
Cooling Tower Emissions, S-46[d]		
Arsenic[b]	0.016	0.024
Beryllium	0.041	0.014
Cadmium[b]	0.00010	0.046
Chromium VI[b]	0.018	0.0014
Copper	0.024	463
Lead[b]	0.003	16
Manganese	0.15	77
Mercury	0.00007	57.9
Nickel	0.023	73
Selenium	0.002	97
Zinc	0.017	6,760
Fuel Pre-Heater, S-45		
Acetaldehyde[b]	0.025	72
Arsenic	0.00056	0.024
Benzene	0.025	6.7
Beryllium	3.37E-5	0.014
Cadmium[b]	0.0031	0.046
Chromium VI[b]	0.040	0.0014
Copper	0.0024	463

Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb./yr-source)
Toxic Air Contaminant	Pounds/year	Risk Screening Trigger Level[a] (lb./yr-source)
Formaldehyde	0.624	33
Hexane	5.08	83,000
Manganese	0.0011	77
Mercury	0.0007	57.9
Naphthalene	0.0017	270
Nickel	0.006	73
PAHs, Total	0.00005	0.043
Selenium	0.00005	97
Toluene	0.0097	38,600
Zinc	0.082	6,760

[a]pursuant to BAAQMD Toxic Risk Management Policy

[b]carcinogenic compound

[c]based upon the worst-case ammonia slip of 10 ppmvd @ 15% O_2 from the A-11 and A-13 SCR systems with ammonia injection

[d]based on San Joaquin River water analysis and cooling tower drift rate.

Table 3 is a summary of the maximum annual regulated air pollutant emissions for the facility from proposed permitted sources. Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.1 and 2-2-305.1), a new major facility with maximum annual pollutant emissions in excess of the trigger levels shown must perform modeling to assess the net air quality impact of that pollutant.

Table 3
Maximum Annual Facility Regulated Air Pollutant Emissions Increase

Pollutant	Cumulative Increase Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	174.3	40
Carbon Monoxide	259.1	100
Precursor Organic Compounds	46.6	N/A
Particulate Matter (PM_{10})	112.2	15
Sulfur Dioxide	48.5	40

[a]Includes emissions from two gas turbines, heat recovery steam generators, natural-gas-fired preheater and cooling tower.

[b]Emissions include 28 cold startups, 83 hot startups, and 111 shutdowns, and 8,626 hours at 100% duct burner capacity with the balance of the time at 100% load at 60F.

[c]For a new major facility.

III Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed CCPP Unit 8 will comply with those requirements.

A. Regulation 2, Rule 2; New Source Review

The primary requirements of New Source Review that apply to the proposed CCPP Unit#8 facility are Section 2-2-301; "Best Available Control Technology Requirement", Section 2-2-302; "Offset Requirements, Precursor Organic Compounds and Nitrogen Oxides, NSR", and Section 2-2-404, "PSD Air Quality Analysis".

1. Best Available Control Technology (BACT) Determinations

Pursuant to Regulation 2-2-206, BACT is defined as the more stringent of:

(a) "The most effective control device or technique which has been successfully utilized for the type of equipment comprising such a source; or

(b) The most stringent emission limitation achieved by an emission control device or technique for the type of equipment comprising such a source; or

(c) Any emission control device or technique determined to be technologically feasible and cost-effective by the APCO; or

(d) The most effective emission control limitation for the type of equipment comprising such a source which the EPA states, prior to or during the public comment period, is contained in an approved implementation plan of any state, unless the applicant demonstrates to the satisfaction of the APCO that such limitations are not achievable. Under no circumstances shall the emission control required be less stringent than the emission control required by any applicable provision of federal, state or District laws, rules or regulations."

The type of BACT described in definitions (a) and (b) must have been demonstrated in practice and approved by a local Air Pollution Control District, CARB, or the EPA and is referred to as "BACT 2". This type of BACT is termed "achieved in practice". The BACT category described in definition (c) is referred to as "technologically feasible/cost-effective" and must have been demonstrated to be effective and reliable on a full-scale unit and shown to be cost-effective on the basis of dollars per ton of pollutant abated. This is referred to as "BACT 1". BACT specifications (for both the "achieved in practice" and "technologically feasible/cost-effective" categories) for various source categories have been compiled in the BAAQMD BACT Guideline.

The following section includes BACT determinations by pollutant for the permitted sources of the proposed CCPP Unit 8. Because each Gas Turbine and its associated HRSG will exhaust through a common stack and be subject to combined emission limitations, the BACT determinations will, in practice, apply to each Gas Turbine/HRSG power train as a combined unit.

Nitrogen Oxides (NO_x)

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for NO_x as 2.5 ppmvd @ 15% O_2 with an averaging period of one hour. This BACT determination was based upon the use of SCR and Low NO_x combustors or a SCONOX System. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595), Delta Energy Center (Application # 19414) and Metcalf Energy Center (Application # 27215). The EPA has accepted this BACT determination as Federal LAER and further established a NO_x concentration of 2.0 ppmvd @ 15% O_2 averaged over three hours as equivalent to 2.5 ppmvd @ 15% O_2, averaged over one hour. CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

  In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.5 ppmvd NO_x @ 15% O_2, averaged over one hour, during all operating modes except gas turbine start-ups and shutdowns. Compliance with this emission limitation will be achieved through the use of a selective catalytic reduction (SCR) system with ammonia injection and will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a NO_x emission of 7.2 lbs./day. BACT is therefore not required.

Top-Down BACT Analysis

In response to comments from EPA Region 9 and various intervenors, the following "top-down" BACT analysis for NO_x has been prepared in accordance with EPA's 1990 Draft New Source Review Workshop Manual. A "top-down" BACT analysis takes into account energy, environmental, economic, and other costs associated with each alternative technology, and the benefit of reduced emissions that the technology would bring.

Available Control Options and Technical Feasibility

In a March 24, 2000 letter sent to local air pollution control districts, EPA Region 9 stated that the SCONO$_x$ Catalytic Adsorption System should be included in any BACT/LAER analysis for combined cycle gas turbine power plant projects since it can achieve the BACT/LAER emission specification for NO$_x$ of 2.5 ppmvd @ 15% O$_2$, averaged over one hour or 2.0 ppmvd @ 15% O$_2$, averaged over three hours. In this letter, EPA stated that ABB Alstom Power, the exclusive licensee for SCONO$_x$ applications, has conducted "full-scale damper testing" that demonstrates that SCONO$_x$ is technically feasible for gas turbines of the size proposed for the CCPP Unit 8 Facility. Stone & Webster Management Consultants, Inc. of Denver Colorado was subsequently hired by ABB to conduct an independent technical review of the SCONO$_x$ technology as well as the full-scale damper testing program. According to the report by Stone & Webster, modifications to the actuators, fiberglass seals, and louver shaft-seal interface are being incorporated to resolve unacceptable reliability and leakage problems. However, no subsequent testing of the redesigned components has occurred to determine if the problems have been solved. Because the feasibility of the "scale-up" of the SCONO$_x$ system for large turbines has not been demonstrated, we do not consider SCONO$_x$ to be a viable control alternative for NO$_x$.

Although we do not consider SCONOx to be a technically feasible control alternative for this project, we have analyzed the collateral impacts of both SCR and SCONO$_x$. We are providing the following analysis for informational purposes only. The analysis shown in Table 4 applies to a single GE Frame 7FA Gas Turbine equipped with DLN combustors and a NO$_x$ emission rate of 25 ppmvd @ 15% O$_2$.

Table 4 Top-Down BACT Analysis Summary for NO$_x$

Control Alternative	Emissions[a] (ton/yr)	Emission Reduction[b] (ton/yr)	Total Annualized Cost[c] ($/yr)	Average Cost-Effectiveness ($/ton)	Incremental Cost-Effectiveness ($/ton)	Toxic Impacts	Adverse Environmental Impacts	Incremental Energy Impact (MM BTU/yr)
SCONO$_x$	788	709	4,122,889	5,815	N/A[d]	No	No	122,000[e]
SCR	788	709	1,557,125	2,196	-	Yes	No	67,900[e]

[a]based upon NO$_x$ emission rate of 25 ppmvd @ 15% O$_2$, and annual firing rate of 17,436,780 MM BTU/yr

[b]based upon NO$_x$ emission rate after abatement of 2.5 ppmvd @ 15% O$_2$, and annual firing rate of 17,436,780 MM BTU/yr

[c]"Cost Analysis for NO$_x$ Control Alternatives for Stationary Gas Turbines", ONSITE SYCOM Energy Corporation, October 15, 1999

[d]does not apply since there is no difference in emission reduction quantity between alternatives

[e]"Towantic Energy Project Revised BACT Analysis", RW Beck, February 18, 2000; based upon increased fuel use to overcome catalyst bed back pressure

Energy Impacts

As shown in Table 4, the use of SCR does not result in any significant or unusual energy penalties or benefits when compared to $SCONO_x$. Although the operation and maintenance of $SCONO_x$ does result in a greater energy penalty when compared to that of SCR, this is not considered significant enough to eliminate $SCONO_x$ as a control alternative.

Economic Impacts

According to EPA's 1990 Draft New Source Review Workshop Manual, "Average and incremental cost effectiveness are the two economic criteria that are considered in the BACT analysis."

As shown in Table 4, the average cost-effectiveness of both SCR and $SCONO_x$ meet the current District cost-effectiveness guideline of $17,500 per ton of NO_x abated. However, the average cost-effectiveness of SCR is approximately 38% of the average cost-effectiveness of $SCONO_x$. These figures are based upon total annualized cost figures from a cost analysis conducted by ONSITE SYCOM Energy Corporation. Although SCONOx will result in greater economic impact as quantified by average cost-effectiveness, this impact is not considered adverse enough to eliminate $SCONO_x$ as a control alternative. See Appendix F for ONSITE SYSCOM cost-effectiveness calculations.

Incremental cost-effectiveness does not apply since SCR and $SCONO_x$ both achieve the current BACT/LAER standard for NO_x of 2.5 ppmvd @ 15% O_2, averaged over one hour and therefore achieve the same NO_x emission reduction in tons per year.

Environmental Impacts

The use of SCR will result in ammonia emissions due to an allowable ammonia slip limit of 5 ppmvd @ 15 % O_2. A health risk assessment using air dispersion modeling showed an acute hazard index of 0.003 and a chronic hazard index of 0.001 resulting from the ammonia slip emissions. In accordance with the District Toxic Risk Management Policy and currently accepted practice, a hazard index of 1.0 or above is considered significant. Therefore, the toxic impact of the ammonia slip resulting from the use of SCR is deemed to be not significant and is not a sufficient reason to eliminate SCR as a control alternative.

The ammonia emissions resulting from the use of SCR may have another environmental impact through its potential to form secondary particulate matter such as ammonium nitrate. Because of the complex nature of the chemical reactions and dynamics involved in the formation of secondary particulates, it is difficult to estimate the amount of secondary particulate matter that will be formed from the emission of a given amount of ammonia. However, it is the opinion of the Research and Modeling section of the BAAQMD Planning Division that the formation of ammonium nitrate in the Bay Area air basin is limited by the formation of nitric acid and not driven by the amount of ammonia in the atmosphere. Therefore, ammonia emissions from the proposed SCR system are not expected to contribute significantly to the formation of secondary particulate matter. This potential environmental impact is not considered adverse enough to justify the elimination of SCR as a control alternative.

A second potential environmental impact that may result from the use of SCR involves the storage and transport of ammonia. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The CCPP Unit 8 Facility will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards. In addition, the CEC has modeled the health impacts arising from a catastrophic release of aqueous ammonia due to spontaneous storage tank failure at the proposed CCPP Unit 8 Facility and found that the impact would not be significant. Therefore, the potential environmental impact due to aqueous ammonia storage at the CCPP Unit 8 Facility does not justify the elimination of SCR as a control alternative. It should be noted that aqueous ammonia, proposed for this project, is far safer than anhydrous ammonia, which is a vapor at atmospheric conditions.

The use of SCONOx will require approximately 360,000 gallons of water per year for catalyst cleaning. This environmental impact does not justify the elimination of $SCONO_x$ as a control alternative.

Conclusion

Neither SCR nor $SCONO_x$ will cause significant energy, economic or environmental impacts. If proposed by the applicant, either would be approvable by the District. The applicant's proposed use of SCR to meet the District's BACT standard for NO_x is therefore acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of three distinct operating modes for each gas turbine/HRSG power train. The first mode is firing of the gas turbine only over its entire operating range from minimum to maximum load. The second mode includes gas turbine firing at maximum load with HRSG duct burner firing. The third mode includes gas turbine firing at maximum load with HRSG duct burner firing and steam injection power augmentation at the gas turbine combustors. Steam injection power augmentation lowers the combustor flame temperature thereby allowing an increased fuel use rate, which in turn increases gas turbine peak generating capacity during periods of high ambient temperature. However, by lowering the combustor flame temperature steam injection can increase CO production.

- Combustion Gas Turbines and Heat Recovery Steam Generators (HRSGs)

District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for CO as 6 ppmvd, @ 15% O_2 with an averaging period of one hour. This BACT determination was based upon the use of CO Catalyst and Dry Low NO_x combustors. CARB has also cited these levels as

BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

When the Crockett Cogeneration facility was originally permitted in 1993 at a CO emission concentration limit of 5.9 ppmvd @ 15% O_2, it established the technologically feasible/cost-effective BACT specification cited above. However, subsequent operation of the facility has shown that they cannot achieve this emission concentration under all operating modes and ambient conditions. Specifically, CO emissions exceed 5.9 ppmvd during minimum load operation under ambient conditions of low temperature and high relative humidity and during peak load operation under ambient conditions of high temperature and moderate to high relative humidity. However, Crockett Cogeneration expects that the gas turbine will comply with a CO emission concentration limit of 10 ppmvd @ 15% O_2 under all loads and ambient conditions with and without duct burner firing, with one exception. Crockett does not expect to consistently meet 10 ppmvd CO, when operating in steam injection power augmentation mode.

None of the three power plants recently permitted in the Bay Area expressed any problem being limited to 10 ppmvd CO, even during steam injection power augmentation mode. All have agreed to operate below 10 ppmvd during all modes of operation, except during start-up and shutdown. Two of the power plants have further agreed to operate below 6 ppmvd during all modes of operation, except during start-up and shutdown. We expect the use of newer low-NOx combustors and oxidizing catalysts to consistently meet 10 ppmvd CO, except during start-up and shutdown.

Therefore, achieved in practice BACT2 for CO is deemed to be 10 ppmvd CO @ 15% O_2 for the combined exhaust from the gas turbine/HRSG duct burners during all modes of operation, except during gas turbine start-up and shutdown. The applicant will typically comply with this BACT specification through the use of dry low-NO_x combustors, which minimize incomplete combustion and/or through the use of an oxidation catalyst.

Two power plants in the Bay Area were recently issued permits with a CO emission concentration limit of 6.0 ppmvd @ 15% O_2 during all operating modes except for gas turbine start-up and shutdown. This limit applies to the combined exhaust from the gas turbine and HRSG and is predicated upon the use of an oxidation catalyst. Because the power plants proposed this limit, it was accepted as meeting BACT 1 for CO. However, it is not considered achieved-in-practice BACT since it has not yet been demonstrated in actual operation. The 6.0 ppmvd will be considered BACT 1 "technologically feasible/cost-effective BACT" for CO emissions.

The CCPP Unit 8 has agreed to a CO emission limit of 6 ppmvd @ 15% O_2 that will apply to all gas turbine/HRSG operating modes except for gas turbine start-up and shutdown. As is the case for Los Medanos Energy Center, this limit will apply to the firing of the turbine alone, turbine operation with HRSG duct burner firing, and steam injection power augmentation mode. The CCPP Unit 8 intends to comply with this BACT specification through the use of dry low-NO_x duct burners, which minimize incomplete combustion, and by the use of a CO oxidation catalyst. The applicant's proposed CO level of 6 ppm therefor complies with BACT.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. This unit will be restricted to 16 hours of operation per day, which results in a CO emission of 2.4 lbs./day. BACT is therefore not required.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6, for Gas Turbine Combined Cycle (>50 Megawatts Heat Input) specifies BACT 1 (Technologically Feasible/Cost Effective) for POC as 2 ppmvd, @ 15% O_2 with an averaging period of one hour. This BACT determination was based upon the use of an Oxidation Catalyst or Dry Low NO_x combustors. This determination is based on recent BAAQMD permits issued for: Los Medanos Energy Center (Application # 18595) and Metcalf Energy Center (Application # 27215). CARB has also cited these levels as BACT in their "Guidance for Power Plant Siting and Best Available Control Technology", June 1999.

- Gas-Fired Fuel Preheater

  During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve POC emissions no greater than 3.0 lbs./day so a BACT determination is not required for this unit.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines/ Heat Recovery Steam Generators (HRSGs)

  District BACT Guideline 89.1.6 specifies BACT for SO_2 for gas turbines with a heat input rating $\geq$ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal SO_2 emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. This corresponds to an SO_2 emission factor of 0.0028 lb./MM Btu. The natural gas sulfur content specification of 1 grain per 100 scf is deemed BACT for SO_2.

- Gas-Fired Fuel Preheater

During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve SO_2 emissions no greater than 0.5 lbs./day based on 16 hours of operation. A BACT determination is therefore not required.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT for PM_{10} for gas turbines with a heat input rating ≥ 50 Megawatts as the exclusive use of PUC-regulated natural gas. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal PM_{10} emissions. Accordingly, the sulfur content of the natural gas will be limited by permit condition to 1 grain/scf. The proposed turbines and duct burners will utilize PUC natural gas exclusively, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as sulfates.

- Cooling Tower

Southern Energy is proposing a cooling tower with a drift rate of 0.0005 %. Based on a recent BACT determination by the San Joaquin Valley Unified APCD (Guideline 8.3.10). The District considers BACT for the cooling towers to be a drift rate of 0.0006 % which will be published in BAAQMD BACT Guideline 181.1. The proposed drift rate is therefore acceptable.

- Gas-Fired Fuel Preheater

During startup a gas-fired fuel preheater will heat the natural gas fuel supply. The exhaust gases from this unit will achieve PM_{10} emissions no greater than 1.4 lbs./day based on 16 hours of operation and therefore a BACT determination is not required.

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x emission increases from permitted sources at facilities, which will emit 15 tons per year or more on a pollutant-specific basis. Because the CCPP facility will emit more than 50 tons per year of NO_x, offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Because CCPP will emit more than 50 tons/year of POC, offsets must be provided, by the applicant, at a ratio of 1.15 to 1.0.

Pursuant to Regulation 2-2-303, emission offsets shall be provided (at a ratio of 1.0:1.0) for PM_{10} emission increases at facilities that will be permitted to emit more than 100 tons of PM_{10} per year. These offsets will be required for the gas turbines, HRSGs and the cooling tower. Pursuant to Regulation 2-2-303.1, emission reduction credits of nitrogen oxides or sulfur dioxide may be used to offset PM_{10} emission increases. The applicant is proposing to offset PM_{10} at a ratio of 3 tons of sulfur dioxide for each ton of PM_{10}. This is the same ratio that that has been used for the nearby Delta Energy Center project. The APCO has determined that the same ratio is acceptable for this application.

It should be noted that in the case of POC and NO_x offsets, District regulations do not require consideration of the location of the source of the emission reduction credits relative to the location of the proposed emission increases that will be offset.

Timing for Provision of Offsets

Pursuant to District Regulation 2-2-311, the applicant must "provide" the required valid emission reduction credits to mitigate the emission increases for the facility prior to the issuance of the Authority to Construct. Pursuant to District Regulation 2, Rule 3, "Power Plants," the Authority to Construct will be issued after the California Energy Commission issues the Certificate for the power plant. Historically, the BAAQMD has not required the applicant to provide the actual banking certificates to the District prior to the issuance of the Authority to Construct. Rather, the District has accepted the applicant's demonstration of control of valid offsets through enforceable contracts or options to purchase as equivalent to the "provision" of offsets as required by Regulation 2-2-311. The actual banking certificates must be surrendered to the District prior to the issuance of the Permit to Operate.

Interpollutant Offset Ratios

Pursuant to District Regulation, 2-2-303.1, an applicant can provide NO_x and/or SO_2 emission credits to offset PM_{10} emission increases at ratios deemed appropriate by the APCO. Pursuant to current District policy, the default interpollutant trade-off ratios for Eastern Contra Costa County are 6 to 1 for NO_x and 4 to 1 for SO_2. These ratios represent "conservative best-estimate values" from an interpollutant trade-off study conducted by Systems Applications International (SAI) for the Shell Refinery located in Martinez, California. More specifically, the analysis specifies a "best estimate" trade-off ratio for the Pittsburg area of 3 to 1 for SO_2 to PM_{10}. Because the

Contra Costa Unit #8 project will be located within 8 miles of the Pittsburg monitoring station the trade-off ratio of 3 tons of SO_2 for each ton of PM_{10} will be used. Please see Appendix C, Attachment 1 for the District policy memorandum regarding this trade-off ratio.

The SAI analysis utilized three methods to estimate the amount of secondary PM_{10} formation resulting from the emission of NO_x and SO_2. The first method was based entirely upon the analysis of air quality data. The second method used a photochemical box model to compute the aerosol yield from a unit of NO_x or SO_2 emissions. The third method used the photochemical model to simulate the effect of an incremental unit of precursor emissions on a typical atmosphere with variable mixing height. The inter-pollutant trade-off ratios generated by the SAI analysis only apply to facilities located in the eastern portion of Contra Costa County. Under current District policy, if an applicant wishes to utilize different (i.e. lower) interpollutant offset ratios, they must submit an analysis for review by the District Planning Division.

Offset Requirements by Pollutant

The applicable offset ratios and the quantity of offsets required are summarized in Appendix C, Table C-1.

POC Offsets

Because the combined emissions from the existing and proposed units at the CCPP facility will exceed 50 tons per year of Precursor Organic Compounds (POCs), the POC emission increases must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

NO_x Offsets

Because the CCPP Unit 8 will emit greater than 50 tons per year of Nitrogen Oxides (as NO_2) from permitted sources, the applicant must provide emission reduction credits (ERCs) of NO_x at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

PM_{10} Offsets

With projected PM_{10} emissions from permitted sources of greater than 100 tons per year, the CCPP Unit 8 triggers the PM_{10} offset requirement of District Regulation 2-2-303. The applicant plans to offset the PM_{10} with SO_2 credits at a ratio of 3:1.

SO_2 Offsets

Pursuant to Regulation 2-2-303, emission reduction credits are not required for the proposed SO_2 emission increases associated with this project since the facility SO_2 emissions will not exceed 100 tons per year. Regulation 2-2-303 does allow for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has not opted to provide such emission offsets.

Current Proposed Offset Package

Table 5 summarizes the current offset obligation of the CCPP Unit 8 and the quantity of valid emission reduction credits (ERCs) under the control of Southern Energy. The emission reduction credits presented in Table 4 exist as federally-enforceable, banked emission reduction credits that have been reviewed for compliance with District Regulation 2, Rule 4, "Emissions Banking", and were subsequently issued as a banking certificate by the BAAQMD.

As indicated, Southern Energy has secured sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the CCPP Unit 8.

Table 5
Emission Reduction Credits Identified by Southern Energy (ton/yr)

	POC[a]	NO_x[b]	PM_{10}[c]
Valid Emission Reduction Credits	53.6	200.5	112.2
Permitted Source Emission Limits	46.6	174.3	112.2
Offsets Required per BAAQMD Calculations	53.6[d]	200.5[d]	112.2[e]

[a]From Banking Certificate # 693.

[b]From Banking Certificate # 693.

[c]SO_2 used at a ratio of 3:1. The following SO_2 Banking Certificates used:

#693 321.90 tons

#694 14.53 tons

#695 0.17 tons

Total 336.60 tons (PM_{10} equivalent 112.2 tons)

[d]Reflects applicable offset ratio of 1.15:1.0 pursuant to Regulation 2-2-302

[e]Reflects applicable offset ratio of 1.0:1.0 pursuant to Regulation 2-2-302

These Banking Certificates originated from the following locations:

Certificate	Company	Location	Original Issue Dates
#693	Gaylord Container	Antioch	6/8/84, 3/12/90, 7/15/93
#694	P G & E	Martinez	7/22/87
#695	Hudson ICS	San Leandro	4/9/97

3. PSD Air Quality Impact Analysis

Pursuant to BAAQMD Regulation 2-2-414.1, the applicant has submitted a modeling analysis that adequately estimates the air quality impacts of the CCPP Unit#8 project. The applicant's analysis was based on EPA-approved models and was performed in accordance with District Regulation 2-2-414.

Pursuant to Regulation 2-2-414.2, the District has found that the modeling analysis has demonstrated that the allowable emission increases from the CCPP Unit#8 facility, in conjunction with all other applicable emissions, will not cause or contribute to a violation of applicable ambient air quality standards for NO_2, CO, and PM_{10} or an exceedence of any applicable PSD increment. **Table 6** summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution form the proposed CCPP Unit#8.

Pursuant to Regulation 2-2-417, the applicant has submitted an analysis of the impact of the proposed source and source-related growth on visibility, soils, and vegetation.

Table 6
California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed CCPP Unit#8
($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	164	225	389	470	---

Please see Appendix E for a detailed discussion of the PSD air quality impact analysis.

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the CCPP Unit#8 project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the CCPP Unit#8 are summarized in Table 2. In accordance with the requirements of the BAAQMD Toxic Risk Management Policy (TRMP) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

Table 7 Health Risk Assessment Results

Source	Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index[a]
Gas Turbines, HRSGs, and Cooling Tower[b]	0.67	0.04	0.2

[a]included for informational purposes only; BAAQMD TRMP does not require an assessment of acute (short-term; i.e. < 24 hour) health impacts

[b]numbers represent combined risk from all sources

The health risk assessment performed by the applicant has been reviewed by the District Toxics Evaluation Section and found to be in accordance with guidelines adopted by Cal/EPA's Office of Environmental Health Hazard Assessment (OEHHA), the California Air Resources Board (CARB), and the California Air Pollution Control Officers Association (CAPCOA). Pursuant to the BAAQMD Risk Management Policy, the increased carcinogenic risk attributed to this project is considered to be not significant since it is less than 1.0 in one million. The chronic hazard index attributed to the emission of non-carcinogenic air contaminants is considered to be not significant since it is less than 1.0. Therefore, the CCPP Unit#8 facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further detail.

C. Other Applicable District Rules and Regulations

Regulation 1, Section 301: Public Nuisance

None of the project's proposed sources of air contaminants are expected to cause injury, detriment, nuisance, or annoyance to any considerable number of persons or the public with respect to any impacts resulting from the emission of air contaminants regulated by the District. In part, the PSD air quality impact analysis insures that the proposed facility will comply with this Regulation.

Regulation 2, Rule 1, Sections 301 and 302:
Authority to Construct and Permit to Operate

Pursuant to Regulation 2-1-301 and 2-1-302, the CCPP Unit 8 has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-41 & S-43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater and S-46 Cooling Tower.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-403, this Preliminary Determination of Compliance (PDOC) serves as the APCO's preliminary decision that the proposed power plant will meet the requirements of all applicable BAAQMD, state, and federal regulations. The PDOC contains proposed permit conditions to ensure compliance with those regulations. Pursuant to Regulation 2-3-304, the PDOC will be subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407.

Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a major facility review permit within 12 months after the facility becomes subject to Regulation 2, Rule 6. Pursuant to Regulation 2-6-212.1, the CCPP Unit#8 will become subject to Regulation 2, Rule 6 upon initial firing of any of the gas turbines (S-41 & S-43) or HRSGs (S-42 & S-44).

Regulation 2, Rule 7: Acid Rain

The CCPP Unit 8 gas turbine units and heat recovery steam generators will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75. District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72. Pursuant to 40 CFR Part 72.30(b)(2)(ii), CCPP Unit#8 must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. Pursuant to 40 CFR Part 72.2, "commence operation" includes the start-up of the unit's combustion chamber.

Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NO_x burner technology and proper combustion practices, the combustion of natural gas at the proposed gas turbines and HRSG duct burners is not expected to result in visible emissions. Specifically, the facility's combustion sources are expected to comply with Regulation 6, including sections 301 (Ringelmann No. 1 Limitation), 302 (Opacity Limitation) with visible emissions not to exceed 20% opacity, and 310 (Particulate Weight Limitation) with particulate matter emissions of less than 0.15 grains per dry standard cubic foot of exhaust gas volume. As calculated in accordance with Regulation 6-310.3, the grain loading resulting from the simultaneous operation of each power train (CTG and HRSG Duct Burners) is 0.0022 gr./dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 5666 mg/l and corresponding maximum PM_{10} emission rate of 1.77 lb./hr, the proposed exempt 10-cell cooling tower is expected to comply with the requirements of Regulation 6.

Particulate matter emissions associated with the construction of the facility are exempt from District permit requirements but are subject to Regulation 6. It is expected that the California Energy Commission will impose conditions on construction activities that will require the use of water and/or chemical dust suppressants to minimize PM_{10} emissions and prevent visible particulate emissions.

Regulation 7: Odorous Substances

Regulation 7-302 prohibits the discharge of odorous substances, which remain odorous beyond the facility property line after dilution with four parts odor-free air. Regulation 7-302 limits ammonia emissions to 5000 ppm. Because the ammonia emissions from the two proposed CTG/HRSG power trains will each be limited by permit condition to 10 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at the CCPP Unit#8.

The use of solvents for cleaning and maintenance at the CCPP Unit#8 is expected to comply with Regulation 8, Rule 4, "General Solvent and Surface Coating Operations" section 302.1 by emitting less than 5 tons per year of volatile organic compounds.

Regulation 9: Inorganic Gaseous Pollutants

Regulation 9, Rule 1, Sulfur Dioxide

This regulation establishes emission limits for sulfur dioxide from all sources and applies to the combustion sources at this facility. Section 301 (Limitations on Ground Level Concentrations) prohibits emissions which would result in ground level SO_2 concentrations in excess of 0.5 ppm continuously for 3 consecutive minutes, 0.25 ppm averaged over 60 consecutive minutes, or 0.05 ppm averaged over 24 hours. Section 302 (General Emission Limitation) prohibits SO_2 emissions in excess of 300 ppmv (dry). With maximum projected SO_2 emissions of < 1 ppmv, the gas turbines and HRSG duct burners are not expected to contribute to noncompliance with ground level SO_2 concentrations and should easily comply with section 302.

Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations

The proposed combustion gas turbines (each rated at 1,872 MM Btu/hr HHV) shall comply with the Regulation 9-3-303 NO_x limit of 125 ppm by complying with a permit condition nitrogen oxide emission limit of 2.5 ppmvd @ 15% O_2. The HRSG duct burners will also be limited to 2.5 ppmvd and therefor comply with this regulation.

Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters

The proposed HRSGs are exempt from Regulation 9, Rule 7, per section 110.5 since they are used to recover sensible heat from the exhaust of the proposed combustion turbines.

Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

Because each of the proposed combustion gas turbines and HRSGs will be limited by permit condition to NO_x emissions of 2.5 ppmvd @ 15% O_2, they are expected to comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

D. CEQA

The CEQA requirements of regulation 2-1-426 are met because the California Energy Commission (CEC) has taken the lead agency roll on this project and are responsible for the EIR, which will fulfill the CEQA requirement. The Application for Certification that the applicant has submitted to the CEC serves as the EIR.

E. MACT

The federal Clean Air Act, Section 112(g), requires that any facility than emits more than 10 tons/year of a HAP (Hazardous Air Pollutant) or 25 tons/year aggregate must do a MACT (Maximum Available Control Technology) determination. The estimated HAP emissions for this facility have been added to Table B-6, the toxic emission summary, in Appendix B. As can be seen in this table, many of the toxics listed are not on the federal HAP list. This table indicates that the HAP emissions are below the MACT trigger levels. Initial calculations from the applicant indicated that the hexane emissions were over 33 tons/year but because of the origin of the hexane emission factor (described in Appendix A) the applicant and the District agreed that the actual hexane emissions can be expected to be much lower than 33 tons/year. The source tests the original hexane emission factor was derived from are from three gas turbines that were tested in Ventura County in 1994. A review of these tests disclosed that in all cases hexane was non-detect (below the instrument range). The emission factor was apparently calculated assuming the detection limit as the concentration. This was a very conservative approach and will overstate the emissions. The District and the applicant are confident that the annual hexane emissions will be below the federal MACT trigger of 10 tons/year. A condition has been added to limit the hexane emissions to 10 tons/year and verification by source test is required.

The District concludes that a MACT determination is not necessary for this facility.

IV Permit Conditions

The following permit conditions will be imposed to ensure that the proposed project complies with all applicable District, State, and Federal Regulations. The conditions limit operational parameters such as fuel use, stack gas emission concentrations, and mass emission rates. Permit conditions will also specify abatement device operation and performance levels. To aid enforcement efforts, conditions specifying emission monitoring, source testing, and record keeping requirements are included. Furthermore, pollutant mass emission limits (in units of lb./hr and lb./MM Btu of natural gas fired) will ensure that daily and annual emission rate limitations are not exceeded.

To provide maximum operational flexibility, no limitations will be imposed on the type, or quantity of gas turbine start-ups or shutdowns. Instead, the facility must comply with daily and annual (consecutive twelve-month) mass emission limits at all times. Compliance with CO and NO_x limitations will be verified by continuous emission monitors (CEMs) that will be in operation during all turbine operating modes, including start-up and shutdown. If the CO and NO_2 CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable gas content and the differing response times of the gas monitors, then start-up and shutdown mass emission rates will be based upon annual source test results. Compliance with POC, SO_2, and PM_{10} mass emission limits will be verified by annual source testing.

In addition to permit conditions that apply to as designed operation of each CTG/HRSG power train and the auxiliary boilers, conditions will be imposed that govern equipment operation during the initial commissioning period when the CTG/HRSG power trains will operate without their SCR systems and oxidation catalysts fully operational. During this commissioning period, the gas turbines will be tested, control systems will be adjusted, and the HRSGs and auxiliary boiler steam tubes will be cleaned. Permit conditions 1 through 12 apply to this commissioning period and are intended to minimize emissions during the commissioning period and insure that those emissions will not contribute to the exceedence of any short-term applicable ambient air quality standard.

CCPP Unit 8
Permit Conditions

Definitions:

1-hour period:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value (HHV) of the fuel, in Btu/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours:	Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.
MM Btu:	million British thermal units
Gas Turbine Start-up Mode:	The lesser of the first 256 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 27(b) and 27(d).
Gas Turbine Shutdown Mode:	The lesser of the 30 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 27(b) through 27(d) until termination of fuel flow to the Gas Turbine.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds. Benzo[a]anthracene Benzo[b]fluoranthene Benzo[k]fluoranthene Benzo[a]pyrene Dibenzo[a,h]anthracene Indenio[1,2,3-cd]pyrene
Corrected Concentration:	The concentration of any pollutant (generally NO_x, CO, or NH_3) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% O_2 by volume on a dry basis.
Commissioning Activities:	All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the CCPP Unit#8 construction contractor to insure safe and reliable steady state operation of the gas turbines, heat recovery steam generators, steam turbine, and associated electrical delivery systems.
Commissioning Period:	The Period shall commence when all mechanical, electrical, and control systems are installed and individual system start-up has been completed, or when a gas turbine is first fired, whichever occurs first. The period shall terminate when the plant has completed performance testing, is available for commercial operation, and has initiated sales to the power exchange.

Precursor Organic Compounds (POCs):	Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate
CEC CPM:	California Energy Commission Compliance Program Manager
CCPP Unit#8:	Contra Costa Power Plant Unit 8

Conditions for the Commissioning Period

1. The owner/operator of the CCPP Unit 8 (CCPP Unit#8) shall minimize emissions of carbon monoxide and nitrogen oxides from S-41 and S-43 Gas Turbines and S-42 and S-44 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period. Conditions 1 through 12 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Conditions 13 through 47 shall apply after the commissioning period has ended.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the S-41 & S-43 Gas Turbine combustors and S-42 & S-44 Heat Recovery Steam Generator duct burners shall be tuned to minimize the emissions of carbon monoxide and nitrogen oxides.

3. At the earliest feasible opportunity, in accordance with the recommendations of the equipment manufacturers and the construction contractor, the A-11 and A-13 SCR Systems and A-12 and A-14 CO Oxidation Catalyst Systems shall be installed, adjusted, and operated to minimize the emissions of carbon monoxide and nitrogen oxides from S-41 & S-43 Gas Turbines and S-42 & S-44 Heat Recovery Steam Generators.

4. Coincident with the as designed operation of A-11 & A-13 SCR Systems, pursuant to conditions 3, 10, 11, and 12, the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall comply with the NO_x and CO emission limitations specified in conditions 20(a) through 20(d).

5. The owner/operator of the CCPP Unit#8 shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired preheater. The plan shall include a description of each commissioning activity, the anticipated duration of each activity in hours, and the purpose of the activity. The activities described shall include, but not be limited to, the tuning of the Dry-Low-NO_x combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NO_x continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

6. During the commissioning period, the owner/operator of the CCPP Unit#8 shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:
   firing hours for each gas turbine and each HRSG
   fuel flow rates to each train
   stack gas nitrogen oxide emission concentrations at P-11 and P-12
   stack gas carbon monoxide emission concentrations P-11 and P-12
   stack gas carbon dioxide concentrations P-11 and P-12

   The monitored parameters shall be recorded at least once every 15 minutes (excluding normal calibration periods or when the monitored source is not in operation) for the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44). The owner/operator shall use District-approved methods to calculate heat input rates, NO_x mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. All records shall be retained on site for at least 5 years from the date of entry and made available to District personnel upon request.

7. The District-approved continuous emission monitors specified in condition 6 shall be installed, calibrated, and operational prior to first firing of the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44). After first firing of the turbines, the detection range of these continuous emission monitors shall be adjusted as necessary to accurately measure the resulting range of CO and NO_x emission concentrations. The type, specifications, and location of these monitors shall be subject to District review and approval.

8. The total number of firing hours of S-41 Gas Turbine and S-42 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-11 SCR System and/or A-12 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-41 Gas Turbine and S-42 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

9. The total number of firing hours of S-43 Gas Turbine and S-44 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-13 SCR System and/or A-14 Oxidation Catalyst System shall not exceed 500 hours during the commissioning period. Such operation of S-43 Gas Turbine and S-44 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR or Oxidation Catalyst Systems fully operational. Upon completion of these activities, the owner/operator shall provide written notice to the District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM_{10}, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

11. Combined pollutant mass emissions from the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) shall not exceed the following limits during the commissioning period. These emission limits shall include emissions resulting from the start-up and shutdown of the Gas Turbines (S-41 & S-43).

NO_x (as NO_2)	8,400 pounds per calendar day	400 pounds per hour
CO	13,000 pounds per calendar day	584 pounds per hour
POC (as CH_4)	535 pounds per calendar day	
PM_{10}	624 pounds per calendar day	
SO_2	297 pounds per calendar day	

12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 20. The source test shall determine NO_x, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-41 & S-43) and the Heat Recovery Steam Generators (HRSGs; S-42 & S-44)

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for SO_2 and PM_{10})

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,227 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NO_x)

15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for PM_{10})

16. The combined cumulative heat input rate for the Gas Turbines (S-41 & S-43) and the HRSGs (S-42 & S-44) shall not exceed 34,900,000 MM Btu per year. (Offsets)

17. The HRSG duct burners (S-42 and S-44) shall not be fired unless its associated Gas Turbine (S-41 and S-43, respectively) is in operation. (BACT for NO_x)

18. Except as provided in Condition No. 8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

19. Except as provided in Condition No. 9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for NO_x)

20. The Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) shall comply with requirements (a) through (h) under all operating scenarios, including duct burner firing mode and steam injection power augmentation mode. Requirements (a) through (h) do not apply during a gas turbine start-up or shutdown. (BACT, PSD, and Toxic Risk Management Policy)

    (a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 20 pounds per hour or 0.0090 lb./MM Btu (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NO_x)

    (c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.013 lb./MM Btu (HHV) of natural gas fired or 29.22 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 6 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

    (e) Ammonia (NH_3) emission concentrations at P-11 and P-12 each shall not exceed 5 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-11 and P-12 each shall not exceed 5.6 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-11 and P-12 each shall not exceed 6.18 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.00588 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-11 and P-12 each shall not exceed 13 pounds per hour or 0.00584 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

21. The regulated air pollutant mass emission rates from each of the Gas Turbines (S-41 and S-43) during a start-up or a shutdown shall not exceed the limits established below. (PSD)

	Cold Start-Up (lb./start-up)	Hot Start-Up (lb./start-up)	Shutdown (lb./shutdown)
Oxides of Nitrogen (as NO_2)	452	189	59
Carbon Monoxide (CO)	990	291	73
Precursor Organic Compounds (as CH_4)	109	26	6

22. The Gas Turbines (S-41 and S-43) shall not be in start-up mode simultaneously. (PSD)

23. Total combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44), including emissions generated during Gas Turbine start-ups and shutdowns shall not exceed the following limits during any calendar day:

(a)	1,994 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	3,602 pounds of CO per day	(PSD)
(c)	468 pounds of POC (as CH_4) per day	(CEQA)
(d)	624 pounds of PM_{10} per day	(PSD)
(e)	297 pounds of SO_2 per day	(BACT)

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44)and the Fuel Gas Preheater (S-45) and the Cooling Tower (S-46), including emissions generated during gas turbine start-ups and shutdowns shall not exceed the following limits during any consecutive twelve-month period:

(a)	174.3 tons of NO_x (as NO_2) per year	(Offsets, PSD)
(b)	259.1 tons of CO per year	(Cumulative Increase)
(c)	46.6 tons of POC (as CH_4) per year	(Offsets)
(d)	112.2 tons of PM_{10} per year	(Offsets, PSD)
(e)	48.5 tons of SO_2 per year	(Cumulative Increase)

25. Toxic and HAP Emission Limits

25.1. The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

4,102 pounds of formaldehyde per year
506 pounds of benzene per year
38 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 1.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

25.2. The maximum projected annual Hazardous Air Pollutant (HAP) emissions from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limit:

20,000 pounds of hexane per year
(US-CAA, Section 112(g))

Conformance with this limit shall be verified by the source testing in condition 32.

26. The owner/operator shall demonstrate compliance with conditions 14 through 17, 20(a) through 20(d), 21, 23(a), 23(b), 24(a), and 24(b) by using properly operated and maintained continuous monitors (during all hours of operation including equipment Start-up and Shutdown periods) for all of the following parameters:

(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(b) Carbon Dioxide (CO_2) or Oxygen (O_2) concentrations, Nitrogen Oxides (NO_x) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.
(c) Ammonia injection rate at A-11 and A-13 SCR Systems
(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

The owner/operator shall record all of the above parameters every 15 minutes (excluding normal calibration periods) and shall summarize all of the above parameters for each clock hour. For each calendar day, the owner/operator shall calculate and record the total firing hours, the average hourly fuel flow rates, and average hourly pollutant emission concentrations.

The owner/operator shall use the parameters measured above and District-approved calculation methods to calculate the following parameters:

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.
(f) Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and (26f) at least once every 15 minutes (excluding normal calibration periods). As specified below, the owner/operator shall calculate and record the following data:

(g) total Heat Input Rate for every clock hour and the average hourly Heat Input Rate for every rolling 3-hour period.
(h) on an hourly basis, the cumulative total Heat Input Rate for each calendar day for the following: each Gas Turbine and associated HRSG combined and all four sources (S-41, S-42, S-43, and S-44) combined.
(i) the average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.
(j) on an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.
(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentrations, NO_x mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.
(l) on a daily basis, the cumulative total NO_x mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

(1-520.1, 9-9-501, BACT, Offsets, NSPS, PSD, Cumulative Increase)

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM_{10}) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO_2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, PM_{10}, and SO_2 mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

28. To demonstrate compliance with Condition 25, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of Formaldehyde, Benzene, and Specified PAHs. Maximum projected annual emissions shall be calculated using the maximum Heat Input Rate of 34,900,000 MM Btu/year and the highest emission factor (pounds of pollutant per MM Btu of Heat Input) determined by any source test of the S-41 & S-43 Gas Turbines and/or S-42 & S-44 Heat Recovery Steam Generators. If this calculation method results in an unrealistic mass emission rate (the highest emission factor occurs at a low firing rate) the applicant may use an alternate calculation, subject to District approval. (TRMP)

29. Within 60 days of start-up of the CCPP Unit#8, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NO_x emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

30. Within 60 days of start-up of the CCPP Unit#8 and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load (including steam injection power augmentation mode) to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO_2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM_{10}) emissions including condensable particulate matter. (BACT, offsets)

31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's

Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM_{10} emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

32. Within 60 days of start-up of the CCPP Unit#8 and on an biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Condition 25. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to condition 28 for any of the compounds listed below are less than the BAAQMD Toxic Risk Management Policy trigger levels shown, then the owner/operator may discontinue future testing for that pollutant:

Benzene	≤	26.8 pounds/year
Formaldehyde	≤	132 pounds/year
Specified PAHs	≤	0.18 pounds/year
(TRMP)		

33. The owner/operator of the CCPP Unit#8 shall submit all reports (including, but not limited to monthly CEM reports, monitor breakdown reports, emission excess reports, equipment breakdown reports, etc.) as required by District Rules or Regulations and in accordance with all procedures and time limits specified in the Rule, Regulation, Manual of Procedures, or Enforcement Division Policies & Procedures Manual. (Regulation 2-6-502)

34. The owner/operator of the CCPP Unit#8 shall maintain all records and reports on site for a minimum of 5 years. These records shall include but are not limited to: continuous monitoring records (firing hours, fuel flows, emission rates, monitor excesses, breakdowns, etc.), source test and analytical records, natural gas sulfur content analysis results, emission calculation records, records of plant upsets and related incidents. The owner/operator shall make all records and reports available to District and the CEC CPM staff upon request. (Regulation 2-6-501)

35. The owner/operator of the CCPP Unit#8 shall notify the District and the CEC CPM of any violations of these permit conditions. Notification shall be submitted in a timely manner, in accordance with all applicable District Rules, Regulations, and the Manual of Procedures. Notwithstanding the notification and reporting requirements given in any District Rule, Regulation, or the Manual of Procedures, the owner/operator shall submit written notification (facsimile is acceptable) to the Enforcement Division within 96 hours of the violation of any permit condition. (Regulation 2-1-403)

36. The stack height of emission points P-11 and P-12 shall each be at least 195 feet above grade level at the stack base. (PSD, TRMP)

37. The Owner/Operator of CCPP Unit#8 shall provide adequate stack sampling ports and platforms to enable the performance of source testing. The location and configuration of the stack sampling ports shall be subject to BAAQMD review and approval.
(Regulation 1-501)

38. Within 180 days of the issuance of the Authority to Construct for the CCPP Unit#8, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous monitors, sampling ports, platforms, and source tests required by conditions 26, 29, 30 and 32. All source testing and monitoring shall be conducted in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

39. Prior to the issuance of the BAAQMD Authority to Construct for the CCPP Unit 8, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 112.2 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the CCPP Unit 8, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 112.2 tons of Particulate Matter less than 10 microns. (Offsets)

41. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.3, the owner/operator of the CCPP Unit#8 shall submit an application to the BAAQMD for a significant revision to the Major Facility Review Permit prior to commencing operation. (Regulation 2-6-404.3)

42. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the CCPP Unit 8 shall not operate either of the gas turbines until either: 1) a Title IV Operating Permit has been issued; 2) 24 months after a Title IV Operating Permit Application has been submitted, whichever is earlier. (Regulation 2, Rule 7)

43. The CCPP Unit 8 shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

44. The owner/operator shall take monthly samples of the natural gas combusted at the CCPP Unit#8. The samples shall be analyzed for sulfur content using District-approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content shall be no more than 1.0 grains/100scf. (cumulative increase)

45. The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum

guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,666 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

46. The owner/operator shall perform a visual inspection of the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD)

47. The Fuel Gas Preheater (S-45) shall not be operated more than 16 hours in any day. (BACT)

V Recommendation

The APCO has concluded that the proposed CCPP Unit 8 power plant, which is composed of the permitted sources listed below, complies with all applicable District rules and regulations. The following sources will be subject to the permit conditions and BACT and offset requirements discussed previously.

S-41 Combustion Gas Turbine #1, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-NO_x Combustors, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-42 Heat Recovery Steam Generator #1, 395 MM Btu per hour, abated by A-11 Selective Catalytic Reduction System and A-12 CO Catalyst System.

S-43 Combustion Gas Turbine #2, General Electric Frame 7FA, 1872 MM Btu per hour, equipped with dry low-NO_x Combustors, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-44 Heat Recovery Steam Generator #2, 395 MM Btu per hour, abated by A-13 Selective Catalytic Reduction System and A-14 CO Catalyst System.

S-45 Gas-Fired Fuel Preheater, 12 MM Btu per hour.

S-46 10-Cell Wet Cooling Tower, 125,000 gallons per minute

Pursuant to District Regulation 2-3-404, this document shall be subject to the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407.

Written comments on this Preliminary Determination of Compliance should be directed to:

Ellen Garvey
Air Pollution Control Officer/Executive Officer
Bay Area Air Quality Management District
939 Ellis Street
San Francisco CA 94109

Appendix A

Emission Factor Derivations

The following physical constants and standard conditions were utilized to derive the criteria-pollutant emission factors used to calculate criteria pollutant and toxic air contaminant emissions.

standard temperature[a]:	70°F
standard pressure[a]:	14.7 psia
molar volume:	385.3 dscf/lbmol
ambient oxygen concentration:	20.95%
dry flue gas factor[b]:	8535 dscf/MM Btu
natural gas higher heating value:	1030 Btu/dscf

[a]BAAQMD standard conditions per Regulation 1, Section 228.

[b]F-factor is based upon the assumption of complete stoichiometric combustion of natural gas. In effect, it is assumed that all excess air present before combustion is emitted in the exhaust gas stream. Value shown reflects the typical composition and heat content of utility-grade natural gas in San Francisco bay area.

Table A-1 summarizes the regulated air pollutant emission factors that were used to calculate mass emission rates for each source. All units are pounds per million Btu of natural gas fired based upon the high heating value (HHV). All emission factors are after abatement by applicable control equipment.

Table A-1
Controlled Regulated Air Pollutant Emission Factors for Gas Turbines and HRSGs

Pollutant	Source			
	Gas Turbine		Gas Turbine & HRSG Combined	
	lb/MM Btu	lb/hr	lb/MM Btu	lb/hr
Nitrogen Oxides (as NO_2)	0.00897[a]	16.8	0.00897[a]	20.0
Carbon Monoxide	0.013[b]	24.5	0.013[b]	29.2
Precursor Organic Compounds	0.00255	4.77	0.00250	5.57
Particulate Matter (PM_{10})	0.0059	11	0.00584	13
Sulfur Dioxide	0.00227	5.19	0.00227	6.18

[a]based upon the permit condition emission limit of 2.5 ppmvd NO_x @ 15% O_2 that reflects the use of dry low-NO_x combustors at the CTG, low-NO_x burners at the HRSG, and abatement by the proposed A-11 and A-13 Selective Catalytic Reduction Systems with ammonia injection

[b]based upon the permit condition emission limit of 6 ppmvd CO @ 15% O_2

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined NO_x emissions from the CTG and HRSG will be limited to 2.5 ppmv, dry @ 15% O_2. This emission limit will also apply when the HRSG duct burners are in operation. This concentration is converted to a mass emission factor as follows:

(2.5 ppmvd)(20.95 - 0)/(20.95 - 15) = 8.8 ppmv NO_x, dry @ 0% O_2

$(8.8/10^6)$(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8535 dscf/MM Btu)

= **0.00897 lb NO_2/MM Btu**

The NO_x mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.00897 lb/MM Btu)(1872 MM Btu/hr) = **16.8 lb NO_x/hr**

The NO_x mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.00897 lb/MM Btu)(2226.5 MM Btu/hr) = **20.0 lb NO_x/hr**

CARBON MONOXIDE EMISSION FACTORS

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the CTG and HRSG duct burner will be conditioned to a maximum controlled CO emission limit of 6 ppmv, dry @ 15% O_2 during all operating modes except gas turbine start-up and shutdown. The emission factor corresponding to this emission concentration is calculated as follows:

(6 ppmv)(20.95 - 0)/(20.95 - 15) = 21.13 ppmv, dry @ 0% O_2

$(21.13/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8535 dscf/MM Btu)

= 0.013 lb CO/MM Btu

The CO mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.013 lb/MM Btu)(1872 MM Btu/hr) = **24.5 lb CO/hr**

The CO mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the CTG and HRSG and is calculated as follows:

(0.013 lb/MM Btu)(2226.5 MM Btu/hr) = **29.2 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Combustion Gas Turbine

General Electric has predicted a maximum POC (non-methane, non-ethane hydrocarbon) emission rate of 4.77 lb/hour for full load operation of the gas turbine alone and 5.57 lb/hr for full load operation of the gas turbine with duct burner firing and steam injection power augmentation. These mass emission rates are derived from the BACT specification for POC of 2 ppmv, dry @ 15% O_2.

This converts to an emission factor as follows:

POC = (4.77 lb/hr)/(1872 MM Btu/hr) = **0.00255 lb/MM Btu**

Converting to a concentration yields:

[(0.00255 lb/MM Btu)(10^6)(385.3 dscf/lbmol)]/[(16 lb CH_4/lb-mol)(8535 dscf/MM Btu)]

= 7.19 ppmvd @ 0% O_2

Converting to 15% O_2:

(7.19 ppmvd)(20.95 – 15)/(20.95) = 2 ppmvd @ 15% O_2

Combustion Gas Turbine and Heat Recovery Steam Generator Combined

General Electric, the turbine vendor, has predicted a maximum POC (non-methane, non-ethane hydrocarbon) emission rate of 5.57 lb/hr for full load operation of the gas turbine with duct burner firing and steam injection power augmentation.

This converts to an emission factor of:

(5.57 lb/hr)/(2226.5 MM Btu/hr) = **0.00250 lb/MM Btu**

Converting to a concentration yields:

[(0.00250 lb/MM Btu)(10^6)(385.3 dscf/lbmol)]/[(16 lb CH_4/lb-mol)(8535 dscf/MM Btu)]

= 7.06 ppmvd @ 0% O_2

Converting to 15% 0_2: (7.06 ppmvd)(20.95 – 15)/(20.95) = 2 ppmvd @ 15% O_2

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Combustion Gas Turbine

General Electric has predicted a PM_{10} emission rate of 11 lb/hr at maximum load for the gas turbine. The corresponding PM_{10} emission factor is therefore:

(11 lb PM_{10}/hr)/(1872 MM Btu/hr) = **0.0059 lb PM_{10}/MM Btu**

The following stack data will be used to calculate the grain loading at standard conditions for full load gas turbine operation without duct burner firing to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	11 lb/hr
flow rate:	1,044,947 acfm @ 12.54% O_2 and 195°F
moisture content:	7.75 % by volume

Converting flow rate to standard conditions (dry, 70°F):

(1,044,947 acfm)(70 + 460 °R/195 + 460 °R)(1 – 0.0775) = 780,007 dscfm

Converting to grains/dscf:

(11 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(780,007 dscfm) = 0.0016 gr/dscf

Converting to 6% O_2 basis:

(0.0016 gr/dscf)[(20.95 - 6)/(20.95 – 12.54)] = 0.0028 gr/dscf @ 6% O_2

Combustion Gas Turbine and HRSG Combined

The PM_{10} emission factor is based upon the General Electric vendor prediction of 13 lb/hr at the maximum combined firing rate of 2226.5 MM Btu/hr during duct burner firing and steam injection power augmentation. The corresponding PM_{10} emission factor is therefore:

(13 lb PM_{10}/hr)/(2226.5 MM Btu/hr) = **0.00584 lb PM_{10}/MM Btu**

It is assumed that this PM_{10} emission factor includes secondary PM_{10} formation of particulate sulfates.

The following stack data will be used to calculate the grain loading for simultaneous CTG and HRSG operation at standard conditions to determine compliance with BAAQMD Regulation 6-310.3.

PM_{10} mass emission rate:	13 lb/hr
typical flow rate:	1,008,429 acfm @ 9.54 % O_2 and 184 °F
typical moisture content:	15.96% by volume

Converting flow rate to standard conditions:

(1,008,429 acfm)(70 + 460 °R/184 + 460 °R)(1 - 0.1596) = 697,463 dscfm

Converting to grains/dscf:

(13 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(697,463 dscfm) = 0.002 gr/dscf

Converting to 6% O_2 basis:

(0.002 gr/dscf)[(20.95 - 6)/(20.95 – 15.96)] = 0.007 gr/dscf @ 6% O_2

SULFUR DIOXIDE EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon an expected maximum natural gas sulfur content of 1.0 grains per 100 scf and a higher heating value of 1030 Btu/scf as specified by PG&E.

The sulfur emission factor is calculated as follows:

(1 gr/100scf)(10^6 Btu/MM Btu)(2 lb SO_2/lb S)/[(7000 gr/lb)(1030 Btu/scf)(100 scf)]

= 0.00277 lb SO_2/MM Btu

The corresponding SO_2 mass emission rate at the maximum gas turbine firing rate of 1872 MM Btu/hr is:

(0.00277 lb SO_2/MM Btu)(1872 MM Btu/hr) = 5.19 lb/hr

The corresponding mass SO_2 emission rate at the maximum combined firing rate of 2226.5 MM Btu/hr is:

(0.00277 lb SO_2/MM Btu)(2226.5 MM Btu/hr) = 6.18 lb/hr

This is converted to an emission concentration as follows:

(0.00277 lb SO_2/MM Btu)(385.3 dscf/lb-mol)(lb-mol/64.06 lb SO_2)(10^6 Btu/8535 dscf)

= 1.95 ppmvd SO_2 @ 0% O_2

which is equivalent to:

(1.95 ppmvd)(20.95 - 15)/20.95 = 0.55 ppmv SO_2, dry @ 15% O_2

Toxic Air Contaminants

The following toxic air contaminant emission factors were used to calculate worst-case emissions rates used for air pollutant dispersion models that estimate the resulting increased health risk to the maximally exposed population. To ensure that the risk is properly assessed, the emission factors are conservative and may overestimate actual emissions.

Table A-2
TAC Emission Factors[a] for Gas Turbines and HRSG Duct Burners

Contaminant	Emission Factor (lb/MM scf)
Acetaldehyde[c]	6.86E-02
Acrolein	2.37E-03
Ammonia[b]	13.7
Benzene[c]	1.36E-02
1,3-Butadiene[c]	1.27E-04
Ethylbenzene	1.8E-02
Formaldehyde[c]	1.10E-01
Hexane	5.28E-01
Naphthalene	1.7E-03
PAHs[c]	1.0E-03
Propylene	1.05
Propylene Oxide[c]	4.78E-02
Toluene	7.26E-02
Xylene	2.89E-02

[a]California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program or Ventura County APCD (VCAPCD, 1995). The Hexane emission factor has been adjusted to yield an emission rate of 10 tons/year. See discussion below.

[b]based upon maximum allowable ammonia slip of 10 ppmv, dry @ 15% O_2 for A-11 and A-13 SCR Systems

[c]carcinogenic compound

The applicant used an emission factor over three times higher than the one in Table A-2. This was considered to be too high because the source tests this emission factor was derived from are from three gas turbines that were tested in Ventura County in 1994. A review of these tests disclosed that in all cases Hexane was non-detect (below the instrument range). The emission factor was apparently calculated assuming the detection limit as the concentration. This was a very conservative approach and can be expected to overstate the emissions. The applicant is confident hexane emissions are less than

10 tons/year and has agreed to a Permit Condition with that limit. The level of hexane emissions will be verified by source test.

It should be noted that the ammonia emission factor shown here is twice what is expected because it is based on the originally proposed concentration of 10 ppmvd and the applicant has agreed to operate with an ammonia concentration no more than 5 ppmvd.

Table A-3
TAC Emission Factors for 10-Cell Cooling Tower

Toxic Air Contaminant	Maximum Concentration in Cooling Tower Return Water (ug/L)	Emission Factor[a] Per Cell (g/sec)
Arsenic[b]	5.71	2.27E-08
Beryllium	15	5.96E-08
Cadmium[b]	0.03	1.19R-10
Trivalent chromium[b]	6.66	2.65E-08
Copper	8.82	3.51E-08
Lead[b]	1.25	4.97E-09
Manganese	54.33	2.16E-07
Mercury	0.03	1.19E-10
Nickel	8.28	3.29E-08
Selenium	0.9	3.58E-09
Zinc	6.3	2.50E-08

[a]based upon maximum drift rate of 0.0005% and operation of cooling tower at maximum flow rate of 125,000 gallons per minute; for example:

Cu = (8.82 ug/L)(0.000005)(12,500 gal/min)(3.785 L/gal)/[(60 sec/min)(1E06 ug/g)]
= 3.51E-07 g/sec

[b]carcinogenic compound

AMMONIA EMISSION FACTOR

<u>Combustion Gas Turbine & Heat Recovery Steam Generator</u>

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to a maximum ammonia exhaust concentration limit of 10 ppmvd @ 15% O_2.

(10 ppmvd)(20.95 - 0)/(20.95 - 15) = 35.2 ppmv NH_3, dry @ 0% O_2

$(35.2/10^6)$(1 lbmol/385.3 dscf)(17 lb NO_2/lbmol)(8535 dscf/MM Btu)

= 0.0133 lb NH_3/MM Btu

The NH_3 mass emission rate based upon the maximum firing rate of the gas turbine alone is calculated as follows:

(0.0133 lb/MM Btu)(1872 MM Btu/hr) = **34.8 lb NO_x/hr**

The NH_3 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG and is calculated as follows:

(0.0133 lb/MM Btu)(2226.5 MM Btu/hr) = **29.5 lb NO_x/hr**

Appendix B

Emission Calculations

Individual and combined heat input rate limits for the Gas turbines, HRSGs, and Fuel Heater are given below in **Table B-1**. These are the basis of permit conditions limiting heat input rates.

Table B-1 Maximum Allowable Heat Input Rates

Source	MM Btu/hour-source	MM Btu/day-source	MM Btu/year-source
S-41 and S-43 Gas Turbines, each	1791	42,984[a]	15,689,160[b]
S-41 CTG and S-42 HRSG, each S-43 CTG and S-44 HRSG, each	2226.5[c]	49,950[d]	17,440,000[e]
S-45 Fuel Heater	12	72	

[a]based upon specified maximum rated heat input of 1791MM Btu/hr and 24 hour per day operation

[b]based upon 8,760 hours of operation at full load (1791 MM Btu/hr)

[c]maximum combined firing rate for gas turbine and HRSG duct burners

[d]based upon maximum duct burner firing of 16 hours per day; calculated as:

(16 hr/day)(2,226.5 MM Btu/hr) + (8 hr/day)(1791 MM Btu/hr) = 49,950 MM Btu/day

[e]based upon maximum annual duct burner firing of 4,313 hr/year-HRSG, 4,303 hr/yr gas turbine full load and 144 hr/yr of startup at one-half full load fuel rate (896 MM Btu/hr); calculated as:

(4,313 hr/yr)(2,226.5 MM Btu/hr) + (4,303 hr/yr)(1,791 MM Btu/hr)
+ (144 hr/yr)(896 MM Btu/day) = 17,440,000 MM Btu/year

Table B-2 Maximum Annual Facility Emissions from Permitted Sources (ton/yr)

Source	NO_2	CO	POC	PM_{10}	SO_2
S-41 Gas Turbine and S-42 HRSG[a]	87.1	129.5	23.3	52.5	24.2
S-43 Gas Turbine and S-44 HRSG[a]	87.1	129.5	23.3	52.5	24.2
S-45 Fuel Heater	0.05	0.02	0.02	0.01	0.003
S-46 Cooling Tower				7.5	
Total Permitted Emissions	**174.3**	**259.1**	**46.6**	**112.2**	**48.5**

[a]includes gas turbine start-up and shutdown emissions

B-1.0 Gas Turbine Start-Up and Shutdown Emission Rate Calculations

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound emission rates from a gas turbine occur during start-up and shutdown periods. The PM_{10}, sulfur dioxide, ammonia, and toxic compound emissions are a function of fuel use rate only and do not exceed typical full load emission rates during start-up.

Table B-3 Gas Turbine Start-Up Emission Rates (lb/start-up)

Pollutant	Cold Start-Up[a]	Hot Start-Up[b]
NO_x (as NO_2)	452	189
CO	990	291
POC	109	26
PM_{10}	47	17
SO_x (as SO_2)	14	5

[a]cold start not to exceed 256 min.

[b]hot start not to exceed 90 min.

Shutdown emissions for NO_x, CO, and POC are presented in Table B-4. These emissions have been predicted by General Electric for a shutdown of 23 min. duration.

Table B-4 Gas Turbine Shutdown Emission Rates (lbs)

Pollutant	Shutdown Emissions
NO_x	59
CO	73
POC	6

Hot Start-Up Emission Rate Calculations

- Maximum duration: 90 min.

NITROGEN OXIDES (as NO_2)

Maximum NO_x emission rate: 164 lb/hr

Total NO_2 = 189 lb/hot start

CARBON MONOXIDE

Maximum CO emission rate: 268 lb/hr

Total CO = 291 lb/hot start

PRECURSOR ORGANIC COMPOUNDS

Total POC = 26.2 lb/hot start

PARTICULATE MATTER (as PM_{10})

- PM_{10} emissions are not increased during start-up
- PM_{10} emission factor based upon full load operation (emission rate of 11 lb/hr)

Total PM_{10} = **16.5 lb PM_{10}/ hot start**

SULFUR DIOXIDE

- SO_2 emissions are not increased during start-up

Total SO_2 = **4.9 lb SO_2/hot start**

Cold Start-Up Emission Rate Calculations

- Maximum duration: 256 min.

NITROGEN OXIDES (as NO_2)

Maximum NO_x emission rate: 170 lb/hr

Total NO_2 = 452 lb/cold start

CARBON MONOXIDE

Maximum CO emission rate: 541 lb/hr

Total CO = 990 lb/cold start

PRECURSOR ORGANIC COMPOUNDS

Total POC = 109 lb/cold start

PARTICULATE MATTER (as PM_{10})

- PM_{10} emissions are not increased during start-up
- PM_{10} emission rate during start-up equals maximum baseload emission rate of 11 lb/hr

Total PM_{10} = **47 lb PM_{10}/cold start**

SULFUR DIOXIDE

- SO_2 emissions are not increased during start-up

Total SO_2 = **14 lb SO_2/cold start**

B-2.0 Worst-Case Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines, HRSGs, Fuel Heater and Cooling Tower.

The Gas Turbine/HRSG emission rates shown in **Table B-5** are the basis of permit condition limits and emission offset requirements and were also used as inputs for the ambient air quality impact analysis. To provide maximum operational flexibility, no limitations will be imposed on the type or quantity of turbine start-ups. Instead, the facility must comply with rolling consecutive twelve month mass emission limits at all times. The mass emission limits are based upon the emission estimates calculated for the following power plant operating envelope:

- 4,304 hours of baseload (100% load) operation per year for each gas turbine
- 4,313 hours of duct burner firing per HRSG per year with steam injection power augmentation at gas turbine combustors
- 42 hot start-ups per gas turbine per year (90 min. each)
- 14 cold start-ups per gas turbine per year (256 min. each)
- 56 shutdowns per gas turbine (23 Min. each)

Table B-5 Maximum Annual Regulated Air Pollutant Emissions for Gas Turbines, HRSGs, Fuel Heater and Cooling Tower

Source (Operating Mode)	NO_2 (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)
S-41 & S-43 Gas Turbines (83 total, 90 min. hot start-ups)	15,679	24,135	2,175	1,320	403
S-41 & S-43 Gas Turbines (28 total, 256 min. cold start-ups)	12,658	27,727	3,054	1,314	386
S-41 & S-43 Gas Turbines (8,608 total hours[a] @ 100% load)	141,085[b]	206,162[b]	39,252[b]	94,688	42,782
S-41 & S-43 Gas Turbines and S-42 & S-44 HRSGs (8,626 total hours[a] w/duct burner firing and steam injection power augmentation)	172,520[c]	252,052[c]	48,047[c]	112,138	53,304
S-41 & S-43 Gas Turbines (111 total, 23 min. shutdowns)	6,527	8,087	629	468	138
S-45 Fuel Heater	91	31	38	18	7
S-46 Cooling Tower				14,405	
Total Emissions (lb/yr)	348,560	518,193	93,195	224,333	97,020
(ton/yr)	**174.3**	**259.1**	**46.6**	**112.2**	**48.5**

[a]total combined firing hours for both turbines

[b]based upon the heat input rate of 1,791 MM Btu/hr for each gas turbine

[c]based upon the maximum combined heat input rate of 2,226.5 MM Btu/hr for each CTG/HRSG power train

B-3.0 Cooling Tower PM_{10} Emissions

It is conservatively assumed that all particulate matter will be emitted as PM_{10}.

Cooling tower circulation rate:	125,000 gpm
maximum total dissolved solids:	5666 ppm
Drift Rate:	0.0005 %

Water mass flow rate:

(125,000 gal/min)(60 min/hr)(8.34 lb/gal) = 62,550,000 lb/hr

Cooling Tower Drift:

(62,550,000 lb/hr)(0.000005) = 312.8 lb/hr

PM_{10} = (5666 ppm)(312.8 lb/hr)/(10^6)
= 1.772 lb/hr
= 42.5 lb/day (24 hr/day operation)
= 14,927 lb/yr (8,424 operating hours per year)
= 7.46 ton/yr

B-4.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-41 & S-43 Gas Turbines, S-42 & S-44 HRSGs, S-46 Cooling Tower and S-45 Fuel Heater are summarized in **Table B-6**. These emission rates were used as input data for the health risk assessment modeling and are based upon a maximum annual heat input rate of 19,507,293 MM Btu per year (18,939 MM scf/yr based upon a fuel HHV of 1030 Btu/scf) for each gas turbine/HRSG pair. The derivation of the emission factors is detailed in Appendix A.

Table B-6 Contra Costa Power Plant, Unit #8 – Emissions (Revised 1/19/01)

	Gas Turbine (including duct burner)					Cooling Tower		Fuel Preheater					HAPS
	Emission Factors, lbs/MMscf				Emiss. Rate per turbine, g/s (4)		Emiss. Rate per cell, g/s (5)	Emission Factors, lb/MMscf			Emission Rate, g/s (6)		Annual Total (T/yr)
Pollutant	CATEF (1)	Ventura County (2)	AP-42, Sup. F (3)	Used in Analysis (7)		Water Conc. ug/L		CATEF (1)	AP-42, Sup. D	Used in Analysis	Max. 1-hr.	Annual ave.	
Acetaldehyde	6.86E-02			6.86E-02	1.87E-02			8.87E-03		8.87E-03	1.29E-05	3.60E-07	1.30
Acrolein	2.37E-02			2.37E-02	6.46E-03								0.45
Ammonia					3.73E+00								
Arsenic						5.71	2.27E-08		2.00E-04	2.00E-04	2.92E-07	8.12E-09	
Benzene	1.36E-02			1.36E-02	3.70E-03			4.31E-03	2.10E-03	4.31E-03	6.28E-06	1.75E-07	0.26
Beryllium						15	5.96E-08		1.20E-05	1.20E-05	1.75E-08	4.87E-10	
Butadiene-1,3	1.27E-04			1.27E-04	3.46E-05								0.00
Cadmium						0.03	1.19E-10		1.10E-03	1.10E-03	1.60E-06	4.47E-08	
Chromium VI						6.66	2.65E-08		1.40E-03	1.40E-03	2.04E-06	5.69E-08	
Copper						8.82	3.51E-08		8.50E-04	8.50E-04	1.24E-06	3.45E-08	
Ethylbenzene	1.79E-02			1.79E-02	4.88E-03								0.34
Formaldehyde	1.10E-01			1.10E-01	3.00E-02			2.21E-01	7.50E-02	2.21E-01	3.22E-04	8.98E-06	2.08
Hexane	2.59E-01	1.75E+00		5.28E-01	1.44E-01				1.80E+00	1.80E+00	2.62E-03	7.31E-05	10.00
Lead						1.25	4.97E-09						
Manganese						54.33	2.16E-07		3.80E-04	3.80E-04	5.54E-07	1.54E-08	
Mercury						0.03	1.19E-10		2.60E-04	2.60E-04	3.79E-07	1.06E-08	
Naphthalene	1.66E-03			1.66E-03	4.53E-04				6.10E-04	6.10E-04	8.89E-07	2.48E-08	0.03
Nickel						8.28	3.29E-08		2.10E-03	2.10E-03	3.06E-06	8.53E-08	
PAHs, Total	1.06E-04	1.00E-03		1.00E-03	2.72E-04				9.60E-06	9.60E-06	1.40E-08	3.90E-10	0.02
Propylene	7.71E-01	1.05E+00		1.05E+00	2.87E-01								
Propylene Oxide	4.78E-02			4.78E-02	1.30E-02								0.90
Selenium						0.9	3.58E-09		2.40E-05	2.40E-05	3.50E-08	9.75E-10	
Toluene	7.10E-02	7.26E-02		7.26E-02	1.98E-02				3.40E-03	3.40E-03	4.96E-06	1.38E-07	1.37
Xylene (Total)	2.61E-02	2.89E-02		2.89E-02	7.87E-03								0.55
Zinc						6.3	2.50E-08		2.90E-02	2.90E-02	4.23E-05	1.18E-06	
												HAPS Total	17.3

(1) CARB's CATEF Version 1.2 Database emission factors, mean values

(2) Ventura County APCD emission factors for gas turbines (1995) reported by the applicant in Appendix I, Public Health Data

(3) Natural gas heat value used to convert units = 1030 Btu/scf

(4) Both annual average and maximum one-hour emission rates are based on the max. turbine fuel use rate = 2.162 MMscf/hr
The ammonia emission rate is estimated by the applicant based on both gas turbines operating at 100 percent load with supplemental firing and 10 ppm slip (15% O2).
Maximum ammonia emissions are = 259,121 lbs/yr per turbine.

(5) Both annual average and maximum one-hour emission rates are based on the max. cooling tower drift rate 0.63 gal/min

(6) Fuel preheater max. fuel usage = 11.92 MMBtu/hr; Total number of hours per year = 244

(7) Hexane emission factor adjusted to conform to 10 ton/year conditon limit.

B-5.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs have been shown in **Table B-5**. The total permitted emission rates shown are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-7
Maximum Hourly and Daily Regulated
Air Pollutant Emission Rates for Baseload Operation
(Excluding Gas Turbine Start-up Emissions)

	NO_2	CO	POC	PM_{10}	SO_2
S-41 and S-43 Gas Turbines[a]					
lb/hr-source	17.1	25.1	4.8	11.0	5.2
lb/day-source	420	602	115	264	125
S-41 & S-42 and S-43 & S-44 Gas Turbine/HRSG Power Train[b]					
lb/hr-power train	20.0	29.2	5.6	13.0	6.1
lb/day-power train	457	668	128	296	141

[a]based upon maximum heat input rate of 1872 MM Btu/hr for each gas turbine

[b]Based upon a maximum combined heat input rate for each gas turbine/HRSG power train of 2,226.5 MM Btu/hr and maximum 16 hours per day duct burner firing

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-8.**

Table B-8
Maximum Daily Regulated Air Pollutant Emissions per
Power Train (lb/day)

Source (operating mode)	NO_2	CO	POC	PM_{10}	SO_2
Gas Turbine (Cold Start-up)	425	990	109	55	26
Gas Turbine (Full load w/o Duct Burner Firing)	36	53	10	29	14
Gas Turbine & HRSG (Full load w/Duct Burner Firing and steam injection power augmentation)	320	468	89	208	99
Gas Turbine (Hot Start-up)	189	291	26	20	9
Total	**997**	**1802**	**234**	**312**	**148**

[a]based upon one 90 min. hot start-up, one 256 min. cold start-up, 16 hours of full load operation with duct burner firing @ 2,226.5 MM Btu/hr with steam injection power augmentation, and 2.2 hours of full load operation without duct burner firing at 1791 MM Btu/hr over a 24 hour period. These are the basis of permit condition daily mass emission limits.

B-6.0 Modeling Emission Rates

The NO_2 emission rates shown in **Table B-9** were used to model the air quality impacts of the CCPP-Unit 8 to determine compliance with State and Federal annual ambient air quality standards for NO_2, CO, SO_2 and PM_{10}. A screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics revealed that the worst-case impacts occur under the equipment operating scenarios listed.

Table B-9
Emission rates used in modeling analysis (lb/hr)

Pollutant Source	Max (1-hour)	Commissioning[a] (1-hour)	Maximum (3-hour)	Maximum (8-hour)	Maximum (24-hour)	Maximum Annual Average
NO_x						
Turbine 1	169.7[b]	169.7[b]	n/a	n/a	n/a	21.6
Turbine 2	19.7	197[c]				21.6
Fuel Gas Preheater	0.45	0.45				0.01
Cooling Tower	---	---				---
CO						
Turbine 1	547[b]	547[b]	n/a	145.1	n/a	n/a
Turbine 2	28.7	287[c]		15.9		
Fuel Gas Preheater	0.05	0.15		0.15		
Cooling Tower	---	---		---		
SO_2						
Turbine 1	6.2	6.2	6.2	n/a	6.2	6.2
Turbine 2	6.2	6.2	6.2		6.2	6.2
Fuel Gas Preheater	0.03	0.03	0.03		0.03	0.03
Cooling Tower	---	---	---		---	---
PM_{10}						
Turbine 1	n/a	n/a	n/a	n/a	11.0	12.0
Turbine 2					11.0	12.0
Fuel Gas Preheater					0.09	0.002
Cooling Tower					1.8	1.7

[a]Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation.
[b]Turbine 1 in Cold Startup.
[c]Commissioning emissions for SCR and CO Oxidation Systems increased by factor of 10.

Appendix C

Emission Offsets

Pursuant to District Regulation 2, Rule 2, Section 302, offsets are required only for permitted sources. Therefore, emission offsets will be required for the NO_x, POC and PM_{10} emission increases associated with S-41 Gas Turbine, S-42 HRSG, S-43 Gas Turbine, S-44 HRSG and S-46 Cooling Tower only. Pursuant to District Regulations, emission offsets are not required for the CO and SO_2 emissions.

Table C-1 Emission Offset Summary

	NO_x	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	174.3	259.1	46.6	112.2	48.5
Offset Requirement Triggered	Yes	N/A	Yes	Yes	No
Offset Ratio	1.15[b]	N/A	1.15[c]	1.00	N/A
Offsets Required (tons)	**200.5**	**0**	**53.6**	**112.2**[d]	**0**

[a]Sum of Gas Turbine (S-41 and S-43) and HRSG (S-42 and S-44) emission increases.

[b]Pursuant to District Regulation 2-2-302, the applicant must provide emission offsets at a ratio of 1.15 to 1.0 since the proposed facility NO_x emissions from permitted sources will exceed 50 tons per year.

[c]Pursuant to District Regulation 2-2-302, an offset ratio of 1.15 applies since the facility POC emissions are greater than 50 tons per year (present plant #18 has POC emissions of 21.8 tons/year).

[d]PM_{10} will be offset with SO_2 at a ratio of 3 tons of SO_2 for 1 ton of PM_{10}. See Appendix C Attachment.

Appendix C Attachment

OCTOBER 18, 1999

TO:	PETER HESS P.H. 10/21/99	VIA:	TOM PERARDI TP 10/18
		CC:	BILL DE BOISBLANC STEVE HILL GLEN LONG DENNIS JANG
FROM:	ROB DE MANDEL		
SUBJECT:	SO_2:PM_{10} OFFSET RATIO FOR DELTA ENERGY CENTER		

As we discussed last Friday, I have reviewed Glen long's 10/14/99 memo, the September 21, 1999 proposal from Sierra Research, and the 1992 SAI report.[1] I have the following comments:

1. As Glen Long pointed out, the Sierra Research analysis was based on annual average emissions and concentration data, while the SAI report analyzed a high PM_{10} winter episode. I agree with Glen that it is more appropriate to base the analysis on the winter episodes that result in the District's highest PM_{10} levels.
2. The SAI Report evaluated SO_2:PM_{10} tradeoff ratios for three Contra Costa County sites: Bethel Island, Concord and Pittsburg. They obtained a range of computed tradeoff ratios from 2.5:1 to 4.6:1. Their "best estimates" were 4:1 for Bethel Island and Concord, and 3:1 for Pittsburg. They recommended a "conservative best-estimate value" of 4:1 for eastern Contra Costa county. In my opinion, a reasonable alternative would be to average the three results, yielding a value of 3.67:1 for eastern CCC. For the Delta Energy Center, using the Pittsburg ratio of 3:1 would also be consistent with SAI's analysis.
3. I recommend that future determinations of SO_2:PM_{10} offset ratios for Bay Area sites outside of eastern CCC should be based on a methodology comparable to that used by SAI in the 1992 report.

[1] Gray, H. A. and M. P. Ligocki, 1992. *Analysis to determine the appropriate trade-off ratios between NO_x, SO_x and PM_{10} emissions for the Shell Martinez Refinery*, SYSAPP-92/006, Systems Applications International, San Rafael, CA.

Appendix D

Health Risk Assessment

As a result of the combustion of natural gas at the proposed Gas Turbines and HRSGs and the presence of dissolved solids (heavy metals) in the cooling tower water, the proposed Contra Costa Unit 8 will emit the toxic air contaminants summarized in Table 2, "Maximum Facility Toxic Air Contaminant (TAC) Emissions". In accordance with the requirements of CEQA, the BAAQMD Risk Management Policy, and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing the air pollutant dispersion model ISCST3 and the multi-pathway cancer risk and hazard index model ACE.

The public health impact of the carcinogenic compound emissions is quantified through the increased carcinogenic risk to the maximally exposed individual (MEI) over a 70-year exposure period. A multi-pathway risk assessment was conducted that included both inhalation and noninhalation pathways of exposure, including the mother's milk pathway. Pursuant to the BAAQMD Risk Management Policy, a project which results in an increased cancer risk to the MEI of less than one in one million over a 70 year exposure period is considered to be not significant and is therefore acceptable.

The public health impact of the noncarcinogenic compound emissions is quantified through the chronic hazard index, which is the ratio of the expected concentration of a compound to the acceptable concentration of the compound. When more than one toxic compound is emitted, the hazard indices of the compounds are summed to give the total hazard index. The acute hazard index quantifies the magnitude of the adverse health affects caused by a brief (no more than 24 hours) exposure to a chemical or group of chemicals. The chronic hazard index quantifies the magnitude of the adverse health affects from prolonged exposure to a chemical caused by the accumulation of the chemical in the human body. The worst-case assumption is made that the exposure occurs over a one-year period. Per the BAAQMD Toxic Risk Management Policy, a project with a total hazard index of 1.0 or less is considered to be not significant and the resulting impact on public health is deemed acceptable.

The results of the health risk assessment performed by the applicant and reviewed by the District Toxics Evaluation Section staff are summarized in **Table D-1**.

Table D-1
Health Risk Assessment Results

Source	Multi-pathway Carcinogenic Risk (risk in one million)	Non-carcinogenic Chronic Hazard Index	Non-carcinogenic Acute Hazard Index[a]
Gas Turbines, HRSGs, and Cooling Tower	0.66	0.04	0.2

[a]included for informational purposes only; the BAAQMD TRMP does not require an assessment the impact due to short-term (< 24 hour) exposure to non-carcinogenic toxic air contaminants

In accordance with the BAAQMD Toxic Risk Management Policy (TRMP), the increased carcinogenic risk and chronic hazard index attributed to this project are each considered to be not significant since they are each less than 1.0. The BAAQMD TRMP does not require an assessment the impact due to short-term (< 24 hour) exposure to non-carcinogenic toxic air contaminants, which is expressed as the acute hazard index.

Based upon the results given in Table D-1, the Contra Costa Unit 8 project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE CONTRA COSTA POWER PLANT UNIT 8 PROJECT

September 2, 2000

BACKGROUND

Southern Energy Delta LLC has submitted a permit application (# 1000) for a proposed 530-MW combined cycle power plant, the Contra Costa Unit 8. The new unit will include two natural gas-fired turbine generators, two supplementally fired heat recovery steam generators, a fuel gas preheater, and a cooling tower. The proposed project will result in an increase in air pollutant emissions of NO_2, CO, PM_{10} and SO_2, triggering regulatory requirements for an air quality impact analysis.

AIR QUALITY IMPACT ANALYSIS REQUIREMENTS

Requirements for air quality impact analysis are given in the District's New Source Review (NSR) Rule: Regulation 2, Rule 2.

The criteria pollutant annual worst case emission increases for the Project are listed in Table E-1, along with the corresponding significant emission rates for air quality impact analysis.

Table E-1
Comparison of proposed project's annual worst case emissions to significant emission rates for air quality impact analysis

Pollutant	Proposed Project's Emissions (tons/year)	Significant Emission Rate (tons/year) (Reg-2-2-304 to 2-2-306)	EPA PSD Significant Emission Rates for major stationary sources
NO_x	174.3	100	40
CO	259.1	100	100
PM_{10}	112.2	100	15
SO_2	48.5	100	40

Table E-1 indicates that the proposed project emissions exceed the significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), and respirable particulate matter (PM_{10}). The source is classified as a major stationary source as defined under the Federal Clean Air Act. Therefore, the air quality impact must be investigated for all pollutants emitted in quantities larger than the EPA PSD significant emission rates (shown in the last column in Table E-1). Table E-1 shows that the NO_2, CO, PM_{10}, and SO_2 ambient impacts from the project must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are into one-hour NO_2 impacts. The Ambient Ratio Methodology (with a default NO_2/NO_x ratio of 0.75) was used for determining the annual-averaged NO_2 concentrations.

Table E-2
Averaging period emission rates used in modeling analysis (g/s)

Pollutant Source	Max (1-hour)	Commissioning[1] (1-hour)	Maximum (3-hour)	Maximum (8-hour)	Maximum (24-hour)	Maximum Annual Average
NO_x						
Turbine 1	21.4	21.4	n/a	n/a	n/a	2.72
Turbine 2	2.48	24.8				2.72
Fuel Gas Preheater	0.0571	0.0571				0.00130
Cooling Tower	—	—				—
CO						
Turbine 1	69.0	69.0	n/a	18.3	n/a	n/a
Turbine 2	3.62	36.2		2.00		
Fuel Gas Preheater	0.0195	0.0195		0.0195		
Cooling Tower	—	—		—		
SO_2						
Turbine 1	0.780	0.780	0.780	n/a	0.780	0.780
Turbine 2	0.780	0.780	0.780		0.780	0.780
Fuel Gas Preheater	0.00416	0.00416	0.00416		0.00416	0.00416
Cooling Tower	—	—	—		—	—
PM_{10}						
Turbine 1	n/a	n/a	n/a	n/a	1.39	1.51
Turbine 2					1.39	1.51
Fuel Gas Preheater					0.0112	0.000260
Cooling Tower					0.224	0.215

[1]Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation.

Air Quality Modeling Results

The maximum predicted ambient impacts of the various modeling procedures described above are summarized in Table E-3 for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure E-1 are the locations of the maximum modeled impacts.

Also shown in Table E-3 are the corresponding significant ambient impact levels listed in Section 233 of the District's NSR Rule. In accordance with Regulation 2-2-414 further analysis is required only for the those pollutants for which the modeled impact is above the significant air quality impact level. Table E-3 shows that the only impact requiring further analysis is the 1-hour NO_2 modeled impacts.

TABLE E-3
Maximum predicted ambient impacts of proposed project ($\mu g/m^3$)
[maximums are in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Break-up Fumigation Impact	Shoreline Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	93.2	34.1	**225.2**	93.2	19
	annual	n/a	n/a	n/a	**0.23**	1.0
CO	1-hour	218	202	**1335**	186	2000
	8-hour	43.7	37.5	**248**	24.2	500
SO_2	1-hour	15.7	2.28	15.1	**15.7**	n/a
	3-hour	6.36	2.05	**13.6**	6.36	25
	24-hour	1.70	0.91	**1.89**	1.70	5
	annual	n/a	n/a	n/a	**0.40**	1.0
PM_{10}	24-hour	4.59	4.05	4.22	**4.59**	5
	annual	n/a	n/a	n/a	**0.22**	1

Background Air Quality Levels

Regulation 2-2-111 entitled "Exemption, PSD Monitoring," exempts an applicant from the requirement of monitoring background concentrations in the impact area (section 414.3) provided the impacts from the proposed project are less than specified levels. Table E-4 lists the applicable exemption standard and the maximum impact from the proposed facility. As shown, all modeled impacts are below the preconstruction monitoring threshold.

TABLE E-4
PSD monitoring exemption levels and maximum impacts
from the proposed project for NO_2 ($\mu g/m^3$)

Pollutant	Averaging Time	Exemption Level	Maximum Impacts from Proposed Project
NO_2	annual	14	0.22

The District-operated Pittsburg 10th Street Monitoring Station was chosen as representative of the background NO_2 concentrations. Table E-5 contains the concentrations measured at the station over the past 5 years (1995 through 1999).

TABLE E-5
Background NO_2 ($\mu g/m^3$) at Pittsburg 10th Street Monitoring Station for the past five years (maximum is in bold type)

	NO_2
Year	Highest 1-hour average
1995	143
1996	133
1997	132
1998	120
1999	**164**

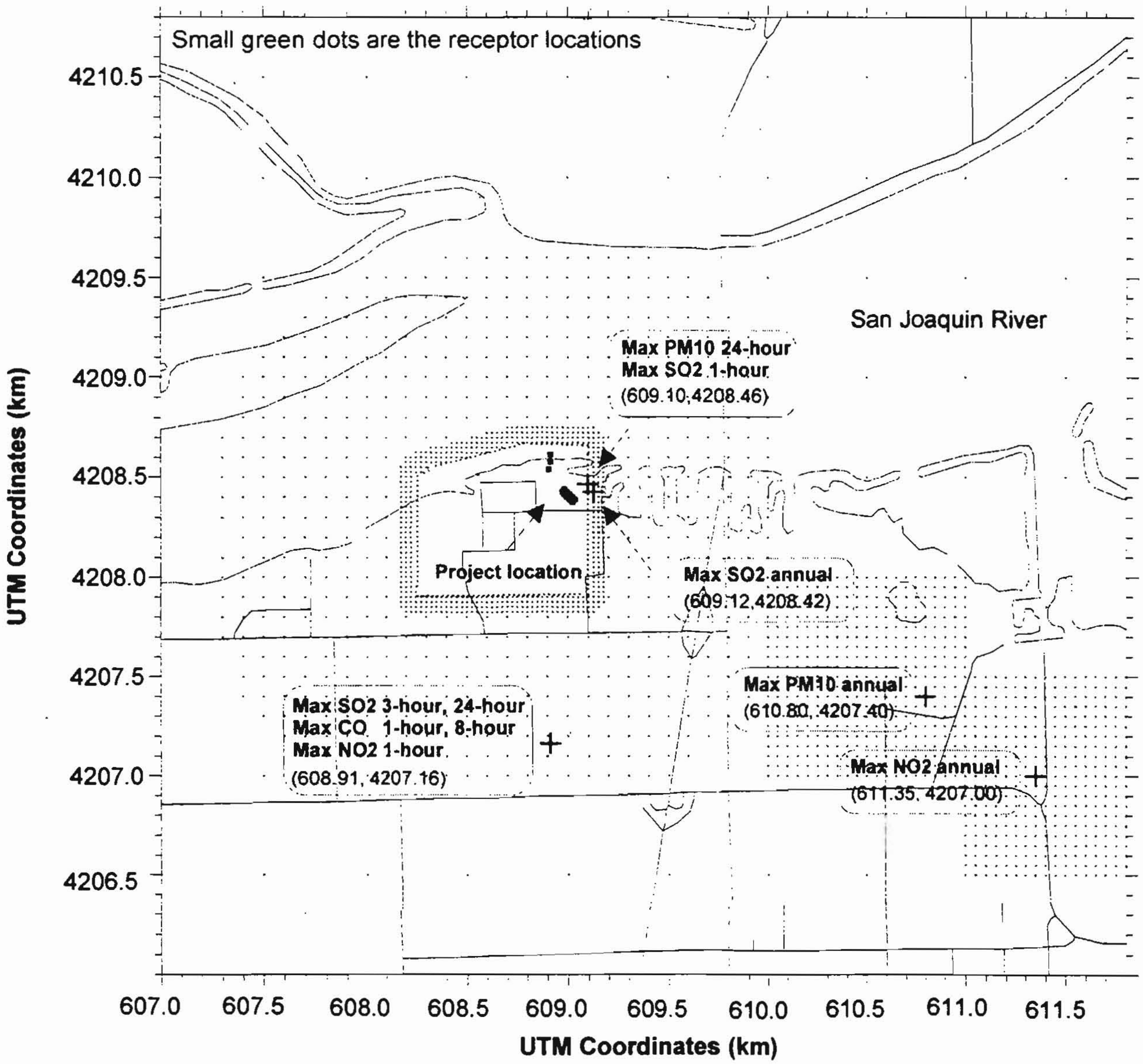

Figure E-1. Location of project maximum impacts.

Table E-6 below contains the comparison of the ambient standards with the proposed project impacts added to the maximum background concentrations. The California ambient NO_2 standard is not exceeded from the proposed project. Therefore, in accordance with Regulation 2-2-414, only a visibility, soils and vegetation impact analysis is further required.

TABLE E-6
California and national ambient air quality standards and ambient air quality levels from the proposed ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	164	225	389	470	---

VISIBILITY, SOILS AND VEGETATION IMPACT ANALYSIS

Visibility impacts were assessed using EPA's VISCREEN visibility screening model. The analysis shows that the proposed project will not cause any impairment of visibility at Point Reyes National Seashore, the closest Class I area.

The project maximum one-hour average NO_2, including background, is 389 $\mu g/m^3$. This concentration is below the California one-hour average NO_2 standard of 470 $\mu g/m^3$. Crop damage from NO_2 requires exposure to concentrations higher than 470 $\mu g/m^3$ for periods longer than one hour.

Maximum project NO_2, CO, SO_2, and PM_{10} concentrations would be less than all of the applicable State and national primary and secondary ambient air quality standards, which are designed to protect the public welfare form any known or anticipated effects, including plant damage. Therefore, the facility's impact on soils and vegetation would be insignificant.

CONCLUSIONS

The results of the air quality impact analysis indicate that the proposed project would not interfere with the attainment or maintenance of applicable AAQS for NO_2, CO, SO_2, and PM_{10}. The applicant's analysis was based on EPA approved models and calculation procedures and was performed in accordance with Section 414 of the District's NSR Rule.

Appendix F

BACT Cost-Effectiveness Data

TABLE A-7
1999 SCONOX COST COMPARISON

			5 MW Class	25 MW Class	150 MW Class
Turbine Model			Solar Centaur 50	GE LM2500	GE Frame 7FA
Turbine Output			4.2 MW	23 MW	170 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		Goalline			
Basic Equipment (A):		Goalline	$620,000	$1,960,000	$7,700,000
Ammonia injection skid and storage	0.00 x A	Goalline	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$49,760	$157,105	$612,238
PE Total:			$671,760	$2,120,916	$8,265,208
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$53,741	$169,673	$661,217
Handling and erection:	0.14 x PE	OAQPS	$94,046	$296,928	$1,157,129
Electrical:	0.04 x PE	OAQPS	$26,870	$84,837	$330,608
Piping:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Insulation:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Painting:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
DI Total:			$201,528	$636,275	$2,479,562
DC Total:			$873,288	$2,757,191	$10,744,770
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Construction and field expenses:	0.05 x PE	OAQPS	$33,588	$106,046	$413,260
Contractor fees:	0.10 x PE	OAQPS	$67,176	$212,092	$826,521
Start-up:	0.02 x PE	OAQPS	$13,435	$42,418	$165,304
Performance testing:	0.01 x PE	OAQPS	$6,718	$21,209	$82,652
Contingencies:	0.03 x PE	OAQPS	$20,153	$63,627	$247,956
IC Total:			$208,246	$657,484	$2,562,214
Total Capital Investment (TCI = DC + IC):			$1,081,534	$3,414,675	$13,306,985
Direct Annual Costs (DAC):					
Operating Costs (O):	24 hrs/day, 7 days/week, 50 weeks/yr				
Operator:	0.5 hr/shift; 25 $/hr for operator pay	OAQPS	$13,125	$13,125	$13,125
Supervisor:	15% of operator	OAQPS	$1,969	$1,969	$1,969
Maintenance Costs (M):					
Labor:	0.5 hr/shift; 25 $/hr for labor pay	OAQPS	$13,125	$13,125	$13,125
Material:	100% of labor cost	OAQPS	$13,125	$13,125	$13,125
Utility Costs:					
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$428,400
Catalyst replace:	** kcfh/MW		$25,880	$106,295	$785,655
Catalyst dispose:	precious metal recovery = 1/3 replace cost	variable	-$8,618	-$35,396	-$261,623
H2 carrier steam	*** lb/hr (93 lb/hr steam/MW @$.006/lb)	variable	$19,686	$107,806	$796,824
H2 reforming	**** CH4 ft3/hr (14ft3/hr/MW @ $.00388/ft3)	variable	$1,916	$10,495	$77,569
H2 skid demand	***** kW (0.6 kW/MW capacity)		$1,270	$6,955	$51,408
Total DAC:			$92,063	$295,458	$1,919,577
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$21,631	$68,293	$266,140
Insurance:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Property tax:	0.01 x TCI	OAQPS	$10,815	$34,147	$133,070
Capital recovery:	10% interest rate, 15 yrs - period; 0.13 x TCI	OAQPS	$138,791	$434,965	$1,646,226
Total IAC:			$206,858	$596,358	$2,203,312
Total Annual Cost (DAC + IAC):			$298,921	$891,816	$4,122,889
NO_x Emission Rate (tons/yr) at 25 ppm:			19.9	83.9	645.9
NO_x Removed (tons/yr) at 2 ppm.	92% removal efficiency		18.3	77.2	594.2
Cost Effectiveness ($/ton):			**$16,327**	**$11,554**	**$6,938**
Electricity Cost Impact (¢/kwh):			**0.847**	**0.462**	**0.289**

* Assume modular SCONOx unit is inserted downstream of HRSG
** 400, 300, 300 kcfth/MW for 5, 25, 150 MW class respectively (s.v.=20kcfh/ft3, $1,500/ft3 catalyst, 7 yr. life)
*** 391, 2139, 15810 lb/hr for 5, 25, 150 MW class respectively
**** 59, 322, 2380 CH4ft3/hr for 5, 25, 150 MW class respectively
***** 3, 14, 102 kW for 5, 25, 150 MW class respectively

1998). This value is derived by a formula specified by CTDEP. The Project's maximum emission rate will be 10 ppm, or 43 percent of the allowable MASC limit.

The use of an SCR for NO_x control in combination with an oxidation catalyst for control of CO may increase particulate emissions in the form of ammonium bi-sulfates. Due to the insignificant amount of sulfur in natural gas fuel this impact will be extremely small. During oil-fired operation (the Project will be limited to 720 hours per year of oil-fired operation) the estimated amount of ammonium bi-sulfate emissions will increase particulate emissions by approximately 60 pounds per hour. This increase has only a minor effect on the maximum predicted air quality impacts from the Project, which are well within National Ambient Air Quality Standards.

An environmental benefit of SCR, when combined with a CO Oxidation Catalyst (Section 1.3), is a decrease in emissions of VOCs. Although the Project is not required to include VOCs in the PSD review as discussed in Section 1.1, the use of an SCR and CO Oxidation Catalyst will ensure that VOC emissions are minimal. The reduction in VOC emissions from SCR/CO Oxidation Catalyst is comparable to that from $SCONO_x$™.

ENERGY ANALYSIS

Use of SCR for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCR reactor. There are other energy requirements associated with chemical transport and operation of equipment, pumps and motors but these are relatively small. Operation of the SCR for the Towantic Project is estimated to reduce electrical output by 1.46 MW or 11,510 MWh of electricity per year[1]. Not only is the electrical output reduced but the fuel use is increased by 135,800 MCF of gas per year.

1.2.4.1.3 ECONOMIC ANALYSIS

Table 3 presents the capital and annualized cost for the SCR control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst), energy penalties and ammonia. All costs are for two GE Frame 7FA gas turbine units, each including one HRSG, which includes the SCR unit.

[1] Based on annual capacity factor of 90%.

issues, poses a serious concern as to whether the Project could secure final construction approval from the Council.

As with the SCR/CO Oxidation Catalyst, SCONO$_x$™ will reduce VOC emissions along with NO_x and CO. The Project is not required to include VOCs in the PSD review, as discussed in Section 1.1, however, SCONO$_x$™ does have the added benefit of decreasing VOC emissions. The reduction in VOC emissions from SCONO$_x$™ is comparable to that from SCR/CO Oxidation Catalyst.

1.2.4.2 .2 ENERGY ANALYSIS

Use of SCONO$_x$™ for NO_x control has an energy penalty due to the energy required to force combustion gases through the SCONO$_x$™ reactor (pressure drop). Pressure drop through the SCONO$_x$™ unit is estimated at 5.25 inches by the manufacturer. This is compared to approximately 3.5 inches of pressure drop for a combined SCR and CO catalyst installed in a HRSG. The pressure drop of 5.25 inches reduces the total plant output by approximately 2.19 MW or 17,266 MWh per year. Not only is the electrical output reduced but the fuel use is increased by 202,200 MCF of gas per year.

Production of the steam used in the regeneration process also imposes a penalty in that the steam is not available to generate electricity. Based on the manufacturer's estimate of low-pressure steam requirements of 15,000 pounds per hour at 600°F and 20 psig, the steam turbine capability of the Project will be reduced by approximately 2.5 MW or 19,710 MWh per year.

The additional energy requirements of the SCONO$_x$™ system (relative to other NO_x control technology) means that the incremental amount of energy will not be supplied by the Project to meet energy needs in the service area. Other power plants will make-up the difference (approximately 4.2 MW) and this will result in a proportional increase in air pollution emissions. These other power plants may emit at levels equal to or greater than the Project.

As with any mechanical system, there are energy requirements associated with the operation of equipment, pumps and motors but these are relatively small. Finally, the SCONO$_x$™ system consumes 200 pounds per hour of natural gas total for regeneration of the catalyst plus leakage. This results in an annual natural gas consumption of 41,800 MCF.

1.2.4.2.3 ECONOMIC ANALYSIS

Table 4 presents the capital and annualized cost for the SCONO$_x$™ control option downstream of a DLN combustor. The costs are itemized to include capital cost of equipment and operation costs for personnel, maintenance, replacement parts (primarily catalyst) and energy costs. These costs are based on general information provided during a meeting with representatives from ABB Environmental. ABB Environmental was not able to provide a specific cost quote for a SCONO$_x$™ system for a GE 7FA combustion turbine with a HRSG. The projected capital costs are based on a SCONO$_x$™ system designed for an ABB GT-24 unit adjusted for the GE 7FA. The SCONO$_x$™ system also reduces