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March 4, 2003

Ms. Theresa Epps
Dockets Unit
California Energy Commission
1516 9th Street
Sacramento, CA 95814

DOCKET
01-AFC-21
DATE MAR 04 2003
RECD. MAR 04 2003

RE: The Tesla Power Project (01-AFC-21)

Dear Ms. Epps:

Enclosed for filing with the California Energy Commission are one original and 12 (Twelve) copies of **the Final Determination of Compliance for the Tesla Power Project (01-AFC-21).**

Sincerely,

Scott A. Galati
on behalf of
Midway Power, LLC

SAG/cp
Enclosures

...Admin\Tesla\Dockets\Cover 03-04-03

February 27, 2003

Mr. Scott Busa
Project Development Manager
Tesla Power Project
7445 Southfront Road
Livermore CA 94550

RE: Tesla Power Project
BAAQMD Application 3506

Dear Mr. Busa:

This is to advise you that the BAAQMD has issued the Final Determination of Compliance for the Tesla Power Project. Pursuant to District Regulation 2-3-404, the FDOC has fulfilled the public notice and 30-day public comment requirements of District Regulations 2-2-406 and 407.

Enclosed for your information is a copy of the Final Determination of Compliance for the Tesla Power Project.

Very truly yours,

William C. Norton
Executive Officer/APCO

WCN:dtj

Enclosure

Final
Determination of Compliance

Tesla Power Project

Bay Area Air Quality Management District
Application 3506

January 22, 2003

Dennis Jang, P.E.
Air Quality Engineer

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I Background

This is the Final Determination of Compliance (FDOC) for the Tesla Power Project (TPP), an 1140-MW, natural-gas fired, combined-cycle merchant power plant proposed by Midway Power, LLC. The power plant will be located at the northeastern edge of Alameda County and will be composed of four nominal 160-MW General Electric 7FA combustion gas turbines, four heat recovery steam generators equipped with 272.2 MM BTU/hr duct burners and two 250-MW steam turbine generators. The facility will also include two exempt 11-cell cooling towers and a 368-hp fire pump diesel engine.

Pursuant to BAAQMD Regulation 2, Rule 3, Section 405, this document serves as the Final Determination of Compliance (FDOC) document for the Tesla Power Project. It will also serve as the evaluation report for the BAAQMD Authority to Construct application number 3506.

The FDOC describes how the proposed Tesla Power Project 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.

In accordance with BAAQMD Regulation 2, Rule 3, Section 404, a draft of this document, (Preliminary Determination of Compliance, or PDOC) was published and circulated to satisfy the public notice, public inspection, and 30-day public comment period requirements of District Regulation 2, Rule 2, Sections 406 and 407. Because the PDOC documents the preliminary decision of the APCO to issue a PSD permit, it is subject to the public notice requirements of Regulation 2-2-405.

Comments on the PDOC were submitted by the applicant, the California Energy Commission, the San Joaquin Valley Air Pollution Control District, EPA Region IX, Mr. Michael Boyd, and Mr. Robert Sarvey. In some cases, changes have been made to this document in response to some of those comments. All comments have been responded to in writing.

II Project Description

1. Permitted Equipment

Midway Power, LLC is proposing a combined-cycle combustion turbine power generation facility with a maximum electrical output of 1,140-MW. As proposed, each natural gas fired combustion turbine generator (CTG) will have a nominal electrical output of 160-MW and the steam produced by the heat recovery steam generators (HRSGs) will feed to two steam turbine generators with a nominal electrical output of 250-MW each.

The Tesla Power Project will consist of the following permitted equipment:

S-1 Combustion Gas Turbine #1, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-5 Combustion Gas Turbine #3, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-6 Heat Recovery Steam Generator #3, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-7 Combustion Gas Turbine #4, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #4, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-9 Fire Pump Diesel Engine, Make and Model to be determined, 368 bhp

And the following exempt equipment:

Cooling Tower #1, 11-Cell, Marley Cooling Technologies, Model W478.50-11; 148,110 gallons per minute

Cooling Tower #2, 11-Cell, Marley Cooling Technologies, Model W478.50-11; 148,110 gallons per minute

The cooling towers are exempt from District permit requirements per BAAQMD Regulation 2-1-128.4 since they are not used for the evaporative cooling of process water where process water is defined as water utilized in a manufacturing process that would contain significant quantities of organic compounds. Furthermore, the cooling towers are also exempt from permit per Regulation 2-1-319 since they each emit less than 5 tons per year of PM_{10} and they are not subject to Regulations 2-1-316, 317, and 318 since their toxic air contaminant emissions are not significant. The cooling tower PM_{10} emission calculations are shown in Appendix B, page B-4.

2. Equipment Operating Scenarios

Turbines and Heat Recovery Steam Generators

Because the Tesla Power Project will be a merchant power plant, the exact operation of the new gas turbine/HRSG power trains will be dictated by market circumstances and demand. However, the following general operating modes are expected to occur at the Tesla Power Project:

Base Load: Maximum continuous combustion turbine output without duct firing for a given set of ambient conditions

Maximum Load: Maximum continuous combustion turbine output with duct burner firing for a given set of ambient 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: May be caused by a major equipment malfunction, or by contractual load and spot sale demand. It may be economically favorable to shutdown one or more turbine/HRSG power trains; this would occur during periods of low overall demand such as late evening and early morning hours

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

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

- 2,800 hours of baseload (100% load) operation per year for each gas turbine @ 62°F
- 5,260 hours of maximum load operation per gas turbine per year
- 27 hot start-ups per gas turbine per year (90 minutes/start-up)
- 6 warm start-ups per gas turbine per year (180 minutes/start-up)
- 12 cold start-ups per gas turbine per year (300 minutes/start-up)
- 45 shutdowns per gas turbine per year

3. Air Pollution Control Strategies and Equipment

The proposed Tesla Power Project 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 minimize NO_x emissions by lowering peak flame temperature by premixing combustion air with a lean fuel mixture. 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.

b. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and 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 operate on a lean fuel mixture that minimizes incomplete combustion and CO emissions. The HRSGs will be equipped with low-NO_x duct burners which are also designed to minimize CO emissions. Furthermore, the gas turbines and HRSGs will be abated by oxidation catalysts which will oxidize the CO emissions and produce CO_2 and water.

c. Oxidation Catalyst, Dry Low-NO_x (DLN) Combustors and Good Combustion Practices to control and 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 low-NO_x burners, which are designed to minimize incomplete combustion and therefore minimize POC emissions. Furthermore, the turbines and HRSGs will be abated by oxidation catalysts which will also reduce 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 burn exclusively PUC-regulated natural gas to minimize SO_2 and PM_{10} emissions. Because the SO_2 emission rate is proportional to the sulfur content of the fuel burned and is not dependent upon the burner type or other combustion characteristics, the use of "low sulfur content" 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.

Table 1 Summary of Control Strategies and Emission Limitations for Gas Turbines and HRSG Duct Burners

Source	Control Strategy and Emission Limit				
	NOx	CO	POC	PM_{10}	SO_2
Gas Turbine & HRSG Power Trains	DLN Combustors/SCR	DLN Combustors/ Oxidation Catalyst	DLN Combustors/ Oxidation Catalyst	PUC-Regulated Natural Gas	PUC-Regulated Natural Gas
	2 ppmv	4 ppmv	2 ppmv	12.75 lb/hr	2 lb/hr

III 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 2 is a summary of the daily maximum regulated air pollutant emissions for the permitted sources at TPP. 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 has the potential to emit 10 pounds or more per highest day of POC, NPOC, NO_x, SO_2, PM_{10}, or CO are subject to the BACT requirement for that pollutant.

Table 2 Maximum Daily Regulated Air Pollutant Emissions for Proposed Sources (lb/day)

Source	Pollutant				
	Nitrogen Oxides (as NO_2)	Carbon Monoxide	Precursor Organic Compounds	Particulate Matter (PM_{10})	Sulfur Dioxide
S-1 Gas Turbine & S-2 HRSG[a]	713.2	1,260.6	167	306	48
S-3 Gas Turbine & S-4 HRSG[a]	713.2	1,260.6	167	306	48
S-5 Gas Turbine & S-6 HRSG[a]	713.2	1,260.6	167	306	48
S-7 Gas Turbine & S-8 HRSG[a]	713.2	1,260.6	167	306	48
S-9 Fire Pump Diesel Engine[b]	134.4	53.5	28.8	2.9	18

[a]NOx, CO, and POC maximum daily emission rates are based upon one 5-hour cold start-up and 19 hours of Gas Turbine /HRSG full load operation at maximum combined firing rate of 2,147.7 MM BTU/hr on a 17°F day; PM_{10} and SO2 maximum daily emission rates are based upon 24 hours of Gas Turbine/HRSG baseload operation at maximum combined firing rate of 2,147.7 MM BTU/hr in one day

[b]emission rates based upon 24 hr/day operation at maximum emission rates; however the fire pump diesel engine normally operates for a maximum of 30 minutes per day (once a week) and the corresponding daily emission rate is much less than shown

Table 3 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 5 ppmvd @ 15% O_2 due to ammonia slip from the A-2, A-4, A-6, and A-8 SCR Systems. The risk screening trigger levels shown are per the District Toxic Risk Management Policy.

Table 3 Maximum Facility Toxic Air Contaminant (TAC) Emissions

Toxic Air Contaminant	Total Project Emissions[a] (lb/yr)	Risk Screening Trigger Level (lb/yr-project)
Acetaldehyde	7,537	72
Acrolein	1,040	3.9
Ammonia	371,336	19,300
Benzene	732	6.7
1,3-Butadiene	7	1.1
Ethylbenzene	984	193,000
Formaldehyde	17,657[b]	33
Hexane	14,248	83,000
Naphthalene	91.2	270
Total PAHs	5.84	0.044
Propylene	42,415	none specified
Propylene Oxide	2,629.6	52
Toluene	3,906	38,600
Xylenes	1,436	57,900
Cooling Towers		
Arsenic	0.26	0.024
Bromide	2.8	330
Cadmium	0.52	0.046
Hexavalent chromium	0.32	0.0014
Copper	0.64	463
Mercury	0.1	57.9
Nickel	0.26	96.5
Manganese	0.9	77
Sulfate	5,580	none specified
Zinc	1.2	6,760
Diesel Exhaust Particulate	6.5	0.64

[a]total combined emissions for S-1, S-3, S-5, & S-7 Gas Turbines, S-2, S-4, S-6, & S-8 HRSGs, exempt cooling towers, and S-9 Fire Pump Diesel Engine

[b]reflects 65% by weight emission reduction from oxidation catalyst

Table 4 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 any of the trigger levels shown must perform modeling to assess the net air quality impact of the proposed facility.

Table 4
Maximum Annual Facility Regulated Air Pollutant Emissions

Pollutant	Permitted Source Emissions[a,b] (tons/year)	PSD Trigger[c] (tons/year)
Nitrogen Oxides (as NO_2)	249.85	100
Carbon Monoxide	335.66	100
Precursor Organic Compounds	60.44	N/A[d]
Particulate Matter (PM_{10})	189.95[e]	100
Sulfur Dioxide	29.55	100

[a]emission increases from proposed gas turbines and heat recovery steam generators and fire pump diesel engine; specified as permit condition limit

[b]includes start-up and shutdown emissions for gas turbines

[c]for a new major facility

[d]there is no PSD requirement for POC since the BAAQMD is designated as nonattainment for the federal 1-hour ambient air quality standard for ozone

[e]does not include PM_{10} emissions from exempt cooling towers

IV Statement of Compliance

The following section summarizes the applicable District Rules and Regulations and describes how the proposed Tesla Power Project 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 TPP 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 it must be commercially available, 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.

Gas Turbines and HRSGs

The following section includes BACT determinations by pollutant for the gas turbines and HRSG duct burners of the proposed Tesla Power Project. 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

  District BACT Guideline 89.1.6 specifies BACT 1 (technologically feasible/cost-effective) for NO_x for a combined cycle gas turbine with a rated output $\geq$ 50 MW as 2.0 ppmvd @ 15% O_2 averaged over three hours or 2.5 ppmvd @ 15% O_2 averaged over one hour, typically achieved through the use of Selective Catalytic Reduction (SCR) with ammonia injection in conjunction with dry low-NOx combustors. The SCAQMD BACT Guideline for gas turbines $\geq$ 3 MW specifies BACT 1 for NO_x as 2.5 ppmvd, @ 15% O_2 with an efficiency correction factor and an assumed averaging period of one hour. This BACT determination was based upon the demonstration of a SCONOX system on a 32 MW combined cycle, baseload turbine currently in operation in Vernon, California. 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.

Based upon our review of CEM data for the ANP Blackstone power plant, a nominal 550-MW combined cycle facility, we have concluded that a NO_x emission concentration of 2.0 ppmvd, @ 15% O_2, averaged over one hour, has been established as "achieved-in-practice" BACT for NO_x. The ANP Blackstone power plant is located in Blackstone, Massachusetts and consists of two ABB GT-4 Gas Turbines rated at 180-MW each with unfired heat recovery steam generators. We reviewed CEM data for approximately 2,313 firing hours for unit 1 and 2,737 firing hours for unit 2 which occurred from April 2001 to April 2002. With the exception of start-up and shutdown periods, the NOx concentrations were below the 2.0 ppmvd limit by a sufficient margin to demonstrate consistent, continuous compliance.

In accordance with design criteria specified by the applicant, each combustion gas turbine is designed to meet a NO_x emission concentration limit of 2.0 ppmvd NO_x @ 15% O_2, averaged over one hour during all operating modes except gas turbine start-ups and shutdowns. This meets the current District BACT 1 determination and meets or exceeds the current EPA and ARB BACT determinations for NO_x. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. The NO_x emissions from the turbine and HRSG will be abated through the use of a selective catalytic reduction (SCR) system with ammonia injection. The NO_x emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

- Heat Recovery Steam Generators (HRSGs)

  Supplemental heat will be supplied to the HRSGs with dry low-NO_x duct burners, which are designed to minimize NO_x emissions. The duct burner exhaust gases will also be abated by the SCR system with ammonia injection and when combined with the gas turbine exhaust, will achieve NO_x emission concentrations of less than or equal to 2.0 ppmvd @ 15% O_2, averaged over one hour.

Top-Down BACT Analysis

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. Although this analysis is based upon a controlled NOx emission rate of 2.5 ppmv instead of the applicable NOx emission rate of 2.0 ppmv, the District has determined that the conclusions of the analysis are applicable to this project.

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 Tesla Power Project. 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 and because the selected control technology, SCR, has been demonstrated in practice to achieve NOx emission concentrations of less than 2 ppmv, averaged over one hour, 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 5 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 5 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 uncontrolled 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 5, 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 5, 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 0.467 and a chronic hazard index of 0.013 resulting from the emission of all non-carcinogenic compounds, including ammonia, from the gas turbines. 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 within the BAAQMD. The potential impact on the formation of secondary particulate matter in the SJVAPCD is not known. 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 TPP will utilize aqeous ammonia in a 19% (by weight) solution. Consequently, the TPP will be required to maintain a Risk Management Plan (RMP) and implement a Risk Management Program to prevent accidental releases of ammonia. 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 TPP facility and found that the impact would not be significant. Therefore, the potential enivronmental impact due to aqueous ammonia storage at the TPP does not justify the elimination of SCR as a control alternative.

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

Because both SCR and $SCONO_x$ can achieve the current accepted BACT/LAER 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 and neither will cause significant energy, economic, or environmental impacts, neither can be eliminated as viable control alternatives. The only aspect of this analysis affected by the current NOx BACT standard of 2.0 ppmvd @ 15% O_2, averaged over one hour is the cost of compliance. The increased cost of control for each technology is not expected to affect the conclusion of this analysis. Therefore, the applicant's proposed use of SCR to meet the NO_x BACT/LAER specification is acceptable.

Carbon Monoxide (CO)

BACT for CO will be analyzed within the context of two 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.

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

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for CO for combined cycle gas turbines with a rated output of ≥ 50 MW as a CO emission concentration of ≤ 4.0 ppmvd @ 15% O_2. This BACT specification is based upon the Sacramento Power Authority (Campbell Soup facility) located in Sacramento County, California. BACT 1 (technologically feasible/cost-effective) is currently not specified. This emission rate limit applies to all operating modes except gas turbine start-up and shutdown.

The applicant has agreed to a CO emission limit of 4.0 ppmvd @ 15% O_2, averaged over any rolling 3-hour period. This satisfies the current BACT 2 limitation as discussed above. Compliance with this emission limitation will be achieved through the use of dry low-NOx combustors which utilize "lean-premixed" combustion technology to reduce the formation of NO_x and CO. CO emissions from the turbine and HRSG will be abated through the use of an oxidation catalyst. The CO emission concentration will be verified by a CEM located at the common stack for each gas turbine/HRSG power train.

Precursor Organic Compounds (POCs)

- Combustion Gas Turbines

There currently is no BACT 1 (technologically feasible/cost-effective) specification for POC for this category of source. Currently, District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for POC for combined cycle gas turbines with an output rating ≥ 50 MW as 2 ppmv, dry @ 15% O_2, which is typically achieved through the use of dry-low NOx combustors and/or an oxidation catalyst. This is based upon the Delta Energy Center and Metcalf Energy Center, which were recently permitted at a POC emission limit of 2 ppmvd @ 15% O_2.

The applicant has proposed a POC emission limitation of 2.36 pounds per hour and 0.00126 lb/MM BTU that are equivalent to an emission concentration of 1 ppmvd @ 15% O_2 for the gas turbine alone. This is lower than the current District BACT 2 specification for POC of 2 ppmv.

The applicant has proposed a combined POC emission limitation of 4.42 pounds per hour and 0.0088 lb/MM BTU that are equivalent to an emission concentration of 1.64 ppmvd @ 15% O_2. This limit applies to the combined exhaust from each gas turbine and corresponding HRSG duct burners. This is lower than the current District BACT 2 specification for POC. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

- Heat Recovery Steam Generators (HRSGs)

The HRSG duct burners will be of dry, low-NO_x design, which minimizes incomplete combustion and therefore the POC emission rate. As stated above, the applicant has proposed a combined POC emission concentration limit of 1.64 ppmvd @ 15% O_2 for simultaneous firing of the turbine and HRSG duct burners. This meets the current BACT 1 specification for POC. Each gas turbine/HRSG pair will achieve this emission limitation through the use of dry low-NO_x burners, good combustion practices and an oxidation catalyst.

Sulfur Dioxide (SO_2)

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT 2 (achieved in practice) for SO_2 for combined cycle gas turbines with an output rating of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will burn exclusively PUC-regulated natural gas with an expected average sulfur content of 0.33 grains per 100 scf, which will result in minimal SO_2 emissions. This corresponds to an SO_2 emission factor of 0.00092 lb/MM BTU. This meets the current BACT 2 specification for SO_2.

- Heat Recovery Steam Generators (HRSGs)

As is the case of the Gas Turbines, BACT for SO_2 for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.33 grains per 100 scf. This corresponds to an SO_2 emission factor of 0.00092 lb/MM BTU. This meets the current BACT 2 specification for SO_2.

Particulate Matter (PM_{10})

- Combustion Gas Turbines

District BACT Guideline 89.1.6 specifies BACT for PM_{10} for combined cycle gas turbines with rated output of $\geq$ 50 MW as the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The proposed turbines will utilize exclusively PUC-regulated natural gas with an average sulfur content of 0.33 gr/100 scf, which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

- Heat Recovery Steam Generators (HRSGs)

BACT for PM_{10} for the HRSG duct burners is deemed to be the exclusive use of clean-burning natural gas with a maximum sulfur content of $\leq$ 1.0 grains per 100 scf. The HRSGs will burn exclusively PUC-regulated natural gas with an average natural gas sulfur content of 0.33 grains per 100 scf which will result in minimal direct PM_{10} emissions and minimal formation of secondary PM_{10} such as ammonium sulfate.

Cooling Towers

The proposed cooling towers are exempt from BAAQMD permit requirements per Regulation 2-1-128.4. Therefore, they are not subject to District BACT requirements. Nevertheless, the proposed cooling towers will be controlled to BACT levels.

The BAAQMD BACT/TBACT workbook does not specify BACT for PM_{10} for wet cooling towers. However, the ARB BACT Clearinghouse cites a BACT specification for PM_{10} for the proposed La Paloma power plant cooling tower as the use of drift eliminators with a maximum drift rate of 0.0006%. The cooling towers for the Los Medanos Energy Center, Delta Energy Center, and Metcalf Energy Center will be equipped with drift eliminators with a guaranteed drift rate of 0.0005%.

The proposed Cooling Towers will also be equipped with drift eliminators with a guaranteed drift rate of 0.0005%. This meets BACT for PM_{10}.

Fire Pump Diesel Engine

Based upon 24 hour per day operation under emergency conditions, the proposed fire pump diesel engine triggers BACT for NO_x, POC, and CO, since its potential to emit for each of those pollutants exceeds 10 pounds per day. The current District BACT limits and the specifications for the proposed engine are summarized in Table 6. The applicant will be required by permit conditions to select and install an engine that satisfies BACT for all pollutants listed.

Table 6 District BACT Limits and Proposed Fire Pump Diesel Engine Specifications

Pollutant	District BACT Specifications[a] (g/bhp-hr)	Engine[b] Specifications (g/bhp-hr)
NOx (as NO_2)	6.9	6.9
CO	2.75	2.75
POC	1.5	1.5
PM_{10}	0.15	0.15

[a]BACT 2 ("achieved in practice") per District BACT Guideline 96.1.2, "IC Engine – Compression Ignition $\geq$ 275 hp output rating"

[b]model not specified; emission rates specified by applicant

2. Emission Offsets

General Requirements

Pursuant to Regulation 2-2-302, federally enforceable emission offsets are required for POC and NO_x (as NO_2) emission increases from permitted sources at facilities which will emit 15 tons per year or more on a pollutant-specific basis. For facilities that will emit more than 50 tons per year of NO_x (as NO_2), offsets must be provided by the applicant at a ratio of 1.15 to 1.0. Pursuant to Regulation 2-2-302.2, POC offsets may be used to offset emission increases of NO_x.

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 new facilities that will be permitted to emit more than 100 tons of PM_{10} per year. 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 at offset ratios determined by the APCO to result in a net air quality benefit. This determination is based upon a case-by-case analysis that includes modeling, public notice, opportunity for public comment, and USEPA concurrance. The location of the NO_x or SO_2 offsets relative to the proposed location of the facility (and resulting PM_{10} emission increase) is considered when determining the acceptability of the offsets.

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 proposed power plant.

Offset Requirements by Pollutant

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

<u>POC Offsets</u>

Because the Tesla Power Project will emit greater than 50 tons of POC per year, the POC emissions must be offset at a ratio of 1.15 to 1.0 pursuant to District Regulation 2-2-302.

<u>NO_x Offsets</u>

Because the Tesla Power Project will emit greater than 50 tons per year of Nitrogen Oxides (NO_x) 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. Pursuant to District Regulation, 2-2-302.2, the applicant has the option to provide POC ERCs to offset the proposed NO_x emission increases at a ratio of 1.15 to 1.0.

PM_{10} Offsets

Because the total PM_{10} emissions from permitted sources will exceed 100 tons per year, the Tesla Power Project triggers the PM_{10} offset requirement of District Regulation 2-2-303. As discussed below, the majority of PM_{10} offsets will come from the future paving of roads at the Altamont Landfill. The authority to construct for the proposed facility may not be issued until sufficient PM_{10} offsets (or interpollutant equivalent offsets) have been approved and the roads have been paved or the paving process has begun.

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 allows for the voluntary offsetting of SO_2 emission increases of less than 100 tons per year. The applicant has opted not to provide such emission offsets.

Offset Package

Table 8 summarizes the current offset obligation of the Tesla Power Project and the quantity of valid emission reduction credits (ERCs) under the control of Midway Power. With the exception of the proposed road paving PM_{10} offsets, the emission reduction credits presented in Table 8 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 banking certificates by the BAAQMD under the applications cited in the table footnotes. If the quantity of offsets issued under any certificate exceeded 40 tons per year for any pollutant, the application was required to fullfill the public notice and public comment requirements of District Regulation 2-4-405. Accordingly, such applications were reviewed by the California Air Resources Board, U.S. EPA, and adjacent air pollution control districts to insure that all applicable federal, state, and local regulations were satisfied.

The PDOC indicated that the majority of the required PM_{10} offsets (178.16 tons per year) would come from emission reductions resulting from road paving at the Altamont Landfill (application 3421). In response to comments received on the proposed emission reductions, the District has reduced the amount of credits available to 98.011 tons per year. Midway Power, LLC has obtained control of 91 tons per year of PM_{10} offsets (Banking Certificate 831) that resulted from the closure of the Crown Zellerbach facility in Antioch in 1984. Thus, Midway Power, LLC has demonstrated that it has control of adequate offsets to offset the Tesla Power Project. If the Altamont Landifll road paving project generates sufficient offsets on its own, they will be utilized to offset the project. If not, the Crown Zellerbach credits will be utilized, as necessary.

As indicated below, Midway Power, LLC currently controls sufficient valid emission reduction credits to offset the emission increases from the permitted sources proposed for the Tesla Power Project. Although Table 8 indicates that there is an outstanding offset obligation of 35.932 tons of NOx, the applicant possess surplus POC offsets of 35.947 tons which can be used to offset NOx emission increases at a ratio of 1:1 per District Regulation 2-2-302.2.

Table 8 Emission Reduction Credits Controlled by Midway Power, LLC as of January 10, 2003 (ton/yr)

Valid Emission Reduction Credits	POC	NO_x	PM_{10}
Banking Certificate #, Owner, Reduction Location			
710, Midway Power, Santa Clara[a]	5.140	0	0
718, Midway Power, Santa Clara[b]	44.995	0	0
719, Midway Power, Palo Alto[c]	4.990	0	0
720, Midway Power, Crockett[d]	0	48.962	0
721, C & H Sugar, Crockett[d]	2.353	0	0.094
778, Midway Power, Union City[e]	0.086	1.564	0.119
798, Midway Power, Fremont[f]	0.148	2.691	0
767, Midway Power, San Francisco[g]	5.682	1.300	0
762, Midway Power, San Leandro[h]	38.993	0	0
773, Midway Power, Hayward[i]	0	21.000	0
780, Midway Power, Los Gatos[j]	2.880	4.960	0.390
800, Midway Power, Oakland[k]	0	0	1.197
830, Midway Power, Antioch[l]	0	171.000	0
831, Mirant, Antioch[m]	0	0	91.000
Proposed Road Paving at Altamont Landfill (App. 3421)	0	0	98.011
Total ERC's Identified	105.447	251.477	190.811
Permitted Source Emission Limits	60.435	249.850	189.950
Offsets Required per BAAQMD Regulations	69.500	287.328	189.950
Outstanding Offset Balance	+35.947	-35.932	+0.861

[a]original certificate #1520, application 7082, Western Spray Painting, issued 4/29/93

[b]original certificate #137, application 6249, National Semiconductor Corporation, issued 4/21/93

[c]original certificate #197, application 8342, Fairchild Advanced R&D Lab, issued 7/10/92

[d]original certificate #509, application 16446, C&H Sugar, issued 2/4/97; certificate 721 under option contract

[e]original certificate #633, application 332, Crown, Cork, & Seal Company, issued 5/16/00

[f]original certificates #771, 775, applications 2300, 2344, Crown, Cork, & Seal Company, issued 10/30/01

[g]original certificate #341, application 12726, Pacific Lithograph Company, issued 7/19/94

[h]original certificate #332, application 12247, Rexam Beverage Can Company, issued 8/17/94

[i]original certificate #16, application 30048, Hunt-Wessson Foods, Inc., issued 8/27/81

[j]original certificate #738, application 1728, Maxxim Medical, Inc., issued 6/6/01

[k]original certificate #419, application 14394, Phoenix Iron Works, issued 7/6/95

[l]original certificate #240, application 9651, Gaylord Container Corporation, issued 7/15/93

[m]original certificate #35, application 30079, Crown Zellerbach Corporation, issued 6/8/84; certificate 831 under option contract

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 TPP 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 TPP 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 exceedance of any applicable PSD increment.

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. The entire PSD air quality impact analysis is contained in Appendix E.

Pursuant to Regulation 2-2-306, a non-criteria pollutant PSD analysis is required for sulfuric acid mist emissions if the proposed facility will emit H_2SO_4 at rates in excess of 38 lb/day and 7 tons per year. However, TPP has agreed to permit conditions limiting total facility H_2SO_4 emissions to 7 tons per year and requiring annual source testing to determine SO_2, SO_3, and H_2SO_4 emissions. If the total facility emissions ever exceed 7 tons per year, then the applicant must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions.

Table 9 Maximum Predicted Ambient Impacts of Proposed TPP (μg/m³)
[maximums are in bold type]

Pollutant	Averaging Time	Commissioning Maximum Impact	Start-up (1-hour)	Inversion Break-up Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	165.8	104	66.2	**187.6**	19
	annual	—	—	—	**0.23**	1.0
CO	1-hour	375.5	**606**	268.9	**1366.8**	2000
	8-hour	—	—	—	**169**	500
PM_{10}	24-hour	—	—	3.2	**4.97**	5
	annual	—	—	—	**0.46**	1

Because the maximum modeled project impacts for annual average NO_2, 1-hour & 8-hour average CO, and 24-hour & annual average PM_{10} did not exceed their corresponding significance levels for air quality impacts per Regulation 2-2-233, further analysis to determine if the corresponding ambient air quality standards will be exceeded per District regulation 2-2-414 is not required. Table 10 summarizes the applicable ambient air quality standards, the maximum background concentrations, and the contribution from the proposed TPP. As shown in Table 10, the worst-case NOx emissions from TPP will not cause or contribute to an exceedance of the California ambient air quality standard for 1-hour NO_2.

Table 10
Applicable California and National Ambient Air Quality Standards (AAQS)
and
Ambient Air Quality Levels from the Proposed TPP (μg/m³)

Pollutant	Averaging Time	Maximum Background	Maximum Project impact	Maximum Project impact plus maximum background	California Standards	National Standards
NO_2	1-hour	199	187.6	387	470	---

B. Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be conducted to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the TPP project. The potential TAC emissions (both carcinogenic and non-carcinogenic) from the TPP 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 approved air pollutant dispersion models.

Table 11 Health Risk Assessment Results

Sources	Multi-pathway Carcinogenic Risk (risk in one million)	Chronic Hazard Index	Acute Hazard Index[a]
Gas Turbines and HRSGs	0.14	0.013	0.467
Fire Pump Diesel Engine	0.8	0.001	--
Exempt Cooling Towers	0.14	0.01	0.039
Maximum Facility Risk:	0.81[b]	0.017	0.472

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

[b]because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the carcinogenic risk numbers do not add directly to determine the maximum facility cancer risk shown

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 TPP facility is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy. Please see Appendix D for further discussion.

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 by concluding that the Tesla Power Project will not interfere with the attainment or maintenance of applicable federal or state health-based ambient air quality standards for NO_2, CO and PM_{10}.

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 Tesla Power Project has submitted an application to the District to obtain an Authority to Construct and Permit to Operate for the proposed S-1, S-3, S-5, & S-7 Gas Turbines, S-2, S-4, S-6, & S-8 Heat Recovery Steam Generators, and S-9 Fire Pump Diesel Engine.

Regulation 2, Rule 1, Sections 426: CEQA-Related Information Requirements

As the lead agency under CEQA for the proposed Tesla Power Project, the California Energy Commission (CEC) will satisfy the CEQA requirements of Regulation 2-1-426.2.1 by producing their Final Certification which serves as an EIR-equivalent pursuant to the CEC's CEQA-certified regulatory program in accordance with CEQA Guidelines Section 15253(b) and Public Resource Code Sections 21080.5 and 25523.

Regulation 2, Rule 2, Sections 307: Denial, Failure of all Facilities to be in Compliance

This regulation requires that the applicant for a new major facility provide a list of all major facilities within the state of California owned or operated by the applicant and certifies under penalty of perjury that such facilities are in compliance with all applicable state and federal emission limitations and standards. The applicant (Midway Power, LLC, a subsidiary of FPL Energy) has submitted a compliance certification for all of its facilities in California. The compliance certification is attached as Appendix G.

Regulation 2, Rule 3: Power Plants

Pursuant to Regulation 2-3-405, this Preliminary Determination of Compliance (PDOC) serves as the APCO's Preliminary determination 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 2-3-404, this PDOC is subject to the public notice, public comment, and public inspection requirements contained in Regulation 2-2-406 and 407. The Authority to Construct, when issued by the District, will be the PSD permit for the TPP.

Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, the owner/operator of the TPP 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 and 2-6-218, the TPP will become subject to Regulation 2, Rule 6 upon completion of construction as demonstrated by first firing of the gas turbines.

Regulation 2, Rule 7: Acid Rain

The Tesla Power Project 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), TPP 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. The proposed start-up date is expected to occur during the first quarter of 2005. The operator has not yet submitted an application for an Acid Rain Permit.

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 (Gas Turbine and HRSG Duct Burners) is 0.0025 gr/dscf @ 6% O_2. See Appendix A for CTG/HRSG grain loading calculations.

With a maximum total dissolved solids content of 1,878 mg/l and corresponding maximum PM_{10} emission rate of 1.4 lb/hr, the two proposed 11-cell cooling towers are 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 conditions of certification imposed by the California Energy Commission will include requirements for 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 slip emissions from the proposed CTG/HRSG power trains will each be limited by permit condition to 5 ppmvd @ 15% O_2, the facility is expected to comply with the requirements of Regulation 7.

Regulation 8: Organic Compounds

The gas turbines and HRSG duct burners are exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively at those sources. The fire pump diesel engine will comply with Regulation 8-2-301 since its emissions will contain a total carbon concentration of less than 300 ppmv, dry.

The use of solvents for cleaning and maintenance at the TPP 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 cause ground level SO_2 concentrations in excess of the limits specified in Regulation 9-1-301 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 1,875.5 MM BTU/hr, HHV) and HRSG duct burners (each rated at 272.2 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 2.0 ppmvd @ 15% O_2. The proposed fire pump diesel engine is not subject to this regulation since it has a maximum heat input rating of approximately 2.67 MM BTU/hr, based upon a maximum rated output of 368 bhp.

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

The proposed S-2, S-4, S-6, and S-8 HRSGs are subject to the emission concentration limits of Regulation 9, Rule 7, section 301 which limits NO_x emissions to 30 ppmv, dry @ 3% O_2 and CO emissions to 400 ppmv, dry @ 3% O_2. To determine if the HRSG duct burners comply with these NO_x emission limits, it would be necessary to install a NOx CEM upstream of the HRSG duct burners since the HRSGs and turbines exhaust through a common stack. Because the combined exhaust from the turbines and HRSGs are subject to a much more stringent BACT limit of 2.0 ppmvd @ 15% O_2, it is reasonable to conclude that the HRSG duct burners comply with the emission limits of Regulation 9, Rule 7. As a practical matter, the HRSG duct burners are therefore subject to Regulation 9, Rule 9.

Regulation 9, Rule 8, Nitrogen Oxides and Carbon Monoxide from Stationary Internal Combustion Engines

The proposed 368 hp fire pump diesel engine is exempt from the requirements of Regulation 9, Rule 8 per Regulation 9-8-110.2, since it will be fired exclusively on diesel fuel. The proposed emergency generator will comply with Regulation 9-8-301.2 ("Emission Limits – Fossil Derived Fuels, Lean-Burn Engines") and Regulation 9-8-301.3 ("CO Emission Limits").

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

Because each of the proposed combustion gas turbines will be limited by permit condition to NO_x emissions of 2.0 ppmvd @ 15% O_2, they will comply with the Regulation 9-9-301.3 NO_x limitation of 9 ppmvd @ 15% O_2.

Regulation 10: Standards of Performance for New Stationary Sources

Regulation 10 incorporates by reference the provisions of Title 40 CFR Part 60. The applicable subparts of 40 CFR Part 60 include Subpart A, "General Provisions", Subpart Da, "Standards of Performance for Electric Utility Steam Generating Units for which Construction is Commenced after September 18, 1978", and Subpart GG "Standards of Performance for Stationary Gas Turbines". The proposed gas turbines and heat recovery steam generators comply with all applicable standards and limits proscribed by these regulations. The applicable emission limitations are summarized below:

Applicable New Source Performance Standards

Source	Requirement	Emission Limitation	Compliance Verification
Gas Turbines and HRSGs	Subpart Da		
	40 CFR 60.44a(a)(1)	0.2 lb NOx/MM BTU, except during start-up, shutdown, or malfunction	Sources limited by permit condition to 0.00904 lb/NOx/MM BTU
	40 CFR 60.44a(a)(2)	25% reduction of potential NOx emission concentration	SCR Systems will comply with this reduction requirement
	40 CFR 60.44a(d)(1)	1.6 lb NOx/MW-hr	0.065 lb NOx/MW-hr at nominal plant rating of 1100 MW
	Subpart GG		
	40 CFR 60.332(a)(1)	100 ppmv NOx, @ 15% O_2, dry	Sources limited by permit condition to 2.5 ppmv NOx @ 15% O_2, dry

V 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 insure 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_x CEMs are not capable of accurately assessing gas turbine start-up and shutdown mass emission rates due to variable O_2 content and the differing response times of the O_2 and NO_x 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 steady-state operation of each CTG/HRSG power train, 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/or oxidation catalysts in place. Commissioning activities include, but are not limited to the testing of the gas turbines, adjustment of control systems, and the cleaning of the HRSG steam tubes. Parts 1 through 14 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 exceedance of any applicable short-term ambient air quality standard.

Although the cooling towers are exempt from District permit requirements, they are subject to parts 52 and 53, that have been included at the request of the California Energy Commission (CEC) so that the District permit conditions and CEC conditions of certification are in agreement. In addition, these conditions have been imposed on the exempt cooling tower in the FDOC and authority to construct issued for the Metcalf Energy Center.

Tesla Power Project
Permit Conditions

(A) Definitions:

Clock Hour:	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 consecutive three-hour period, not including start-up or shutdown periods
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in minutes
MM BTU:	million british thermal units
Gas Turbine Start-up Mode:	The lesser of the first 300 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 parts 24(b) and 24(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 Parts 24(b) through 24(d) until termination of fuel flow to the Gas Turbine
Gas Turbine Cold Start-up:	A gas turbine start-up that occurs more than 48 hours after a gas turbine shutdown
Gas Turbine Hot Start-up:	A gas turbine start-up that occurs within 8 hours of a gas turbine shutdown
Gas Turbine Warm Start-up:	A gas turbine start-up that occurs between 8 hours and 48 hours of a gas turbine shutdown
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to be 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 Indeno[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 points P-1 (combined exhaust of S-1 Gas Turbine and S-2 HRSG duct burners), P-2 (combined exhaust of S-3 Gas Turbine and S-4 HRSG duct burners), P-3 (combined exhaust of S-5 Gas Turbine and S-6 HRSG duct burners), P-4 (combined exhaust of S-7 Gas Turbine and S-8 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 TPP 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. The commissioning period shall not exceed 180 days under any circumstances. The period shall be determined separately for each power train representing a unique combination of one combustion turbine and one steam generator.

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
TPP:	Tesla Power Project

(B) Applicability:

Parts 1 through 14 shall only apply during the commissioning period as defined above. Unless otherwise indicated, Parts 15 through 61 shall apply after the commissioning period has ended.

Conditions for the Commissioning Period

1. The owner/operator of the Tesla Power Project (TPP) shall minimize emissions of carbon monoxide and nitrogen oxides from S-1, S-3, S-5, and S-7 Gas Turbines and S-2, S-4, S-6, and S-8 Heat Recovery Steam Generators (HRSGs) to the maximum extent possible during the commissioning period.

2. At the earliest feasible opportunity in accordance with the recommendations of the equipment manufacturers and the construction contractor, the owner/operator shall tune the S-1, S-3, S-5, & S-7 Gas Turbine combustors and S-2, S-4, S-6, & S-8 Heat Recovery Steam Generator duct burners 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, owner/operator shall install, adjust, and operate the A-1, A-3, A-5, & A-7 Oxidation Catalysts and A-2, A-4, A-6, & A-8 SCR Systems to minimize the emissions of carbon monoxide and nitrogen oxides from S-1, S-3, S-5, & S-7 Gas Turbines and S-2, S-4, S-6, & S-8 Heat Recovery Steam Generators.

4. Coincident with the steady-state operation of A-2, A-4, A-6, & A-8 SCR Systems and A-1, A-3, A-5, & A-7 Oxidation Catalysts pursuant to parts 3, 9, 10, and 11, the owner/operator shall operate the Gas Turbines (S-1, S-3, S-5, & S-7) and the HRSGs (S-2, S-4, S-6, & S-8) in such a manner as to comply with the NO_x and CO emission limitations specified in parts 24(a) through 24(d).

5. The owner/operator of the TPP shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-1, S-3, S-5, or S-7 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs, and steam turbines. 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 required emission control systems, 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-1, S-3, S-5, & S-7)

and HRSGs (S-2, S-4, S-6, & S-8) without abatement by their respective oxidation catalysts and/or SCR Systems. The owner/operator shall not fire any of the Gas Turbines (S-1, S-3, S-5, or S-7) sooner than 28 days after the District receives the commissioning plan.

6. During the commissioning period, the owner/operator of the TPP shall demonstrate compliance with parts 13, 14, and 15 (excluding fuel sulfur content limit) through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

   firing hours
   fuel flow rates
   stack gas nitrogen oxide emission concentrations,
   stack gas carbon monoxide emission concentrations
   stack gas oxygen concentrations.

   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-1, S-3, S-5, & S-7), HRSGs (S-2, S-4, S-6, & S-8). The owner/operator shall use District-approved methods to calculate heat input rates, nitrogen dioxide mass emission rates, carbon monoxide mass emission rates, and NO_x and CO emission concentrations, summarized for each clock hour and each calendar day. The owner/operator shall retain records on site for at least 5 years from the date of entry and make such records available to District personnel upon request.

7. The owner/operator shall install, calibrate, and operate the District-approved continuous monitors specified in part 6 prior to first firing of the Gas Turbines (S-1, S-3, S-5, & S-7) and Heat Recovery Steam Generators (S-2, S-4, S-6, & S-8). After first firing of the turbines, the owner/operator shall adjust the detection range of these continuous emission monitors 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 owner/operator shall not fire the S-1 Gas Turbine and S-2 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-1 SCR System and/or abatement of carbon monoxide emissions by A-2 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-1 Gas Turbine and S-2 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. 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 300 firing hours without abatement shall expire.

9. The owner/operator shall not fire the S-3 Gas Turbine and S-4 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-3 SCR System and/or abatement of carbon monoxide emissions by A-4 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-3 Gas Turbine and S-4 HRSG without

abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. 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 300 firing hours without abatement shall expire.

10. The owner/operator shall not fire the S-5 Gas Turbine and S-6 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-5 SCR System and/or abatement of carbon monoxide emissions by A-6 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-5 Gas Turbine and S-6 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. 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 300 firing hours without abatement shall expire.

11. The owner/operator shall not fire the S-7 Gas Turbine and S-8 Heat Recovery Steam Generator without abatement of nitrogen oxide emissions by A-5 SCR System and/or abatement of carbon monoxide emissions by A-6 Oxidation Catalyst for more than 300 hours during the commissioning period. Such operation of S-5 Gas Turbine and S-6 HRSG without abatement shall be limited to discrete commissioning activities that can only be properly executed without the SCR system and/or oxidation catalyst in place. 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 300 firing hours without abatement shall expire.

12. 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-1, S-3, S-5, & S-7), Heat Recovery Steam Generators (S-2, S-4, S-6, & S-8) and S-9 Fire Pump Diesel Engine during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in part 29.

13. The owner/operator shall not operate the Gas Turbines (S-1, S-3, S-5, & S-7) and Heat Recovery Steam Generators (S-2, S-4, S-6, & S-8) in a manner such that the combined pollutant emissions from these sources will 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-1, S-3, S-5, & S-7).

NO_x (as NO_2)	3,732 pounds per calendar day	622 pounds per hour
CO	2,289 pounds per calendar day	381.6 pounds per hour
POC (as CH_4)	1,080 pounds per calendar day	
PM_{10}	306 pounds per calendar day	
SO_2	48 pounds per calendar day	

14. No less than 45 days prior to the end of the Commissioning Period, the Owner/Operator shall conduct District and CEC approved source tests using external continuous emission monitors

to determine compliance with the emission limitations specified in part 25. The source tests 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 and shall include at least one cold start, one warm start, and one hot start. 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 part. 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 30 days of the source testing date.

Conditions for the Gas Turbines (S-1, S-3, S-5, & S-7) and the Heat Recovery Steam Generators (HRSGs; S-2, S-4, S-6, & S-8)

15. The owner/operator shall fire the Gas Turbines (S-1, S-3, S-5, and S-7) and HRSG Duct Burners (S-2, S-4, S-6, and S-8) exclusively on natural gas with a maximum sulfur content of 0.33 grain per 100 standard cubic feet. To demonstrate compliance with this limit, the operator of S-1 through S-8 shall sample and analyze the gas from each supply source at least once every 30 consecutive days to determine the sulfur content of the gas.
(BACT for SO_2 and PM_{10})

16. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, S-5 & S-6, and S-7 & S-8) exceeds 2,147.7 MM BTU (HHV) per hour, averaged over any rolling three hour period. (PSD for NO_x)

17. The owner/operator shall not operate the units such that the combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-1 & S-2, S-3 & S-4, S-5 & S-6, and S-7 & S-8) exceeds 51,544.8 MM BTU (HHV) per calendar day. (PSD for PM_{10})

18. The owner/operator shall not operate the units such that the combined cumulative heat input rate for the Gas Turbines (S-1, S-3, S-5, & S-7) and the HRSGs (S-2, S-4, S-6, & S-8) exceeds 62,985,372 MM BTU (HHV) per year. (Offsets)

19. The owner/operator shall not fire the HRSG duct burners (S-2, S-4, S-6, and S-8) unless its associated Gas Turbine (S-1, S-3, S-5, and S-7, respectively) is in operation.
(BACT for NO_x)

20. The owner/operator shall ensure that the S-1 Gas Turbine and S-2 HRSG are abated by the properly operated and properly maintained A-2 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-2 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

21. The owner/operator shall ensure that the S-3 Gas Turbine and S-4 HRSG are abated by the properly operated and properly maintained A-4 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-4 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

22. The owner/operator shall ensure that the S-5 Gas Turbine and S-6 HRSG are abated by the properly operated and properly maintained A-6 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-6 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

23. The owner/operator shall ensure that the S-7 Gas Turbine and S-8 HRSG are abated by the properly operated and properly maintained A-8 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-8 SCR catalyst bed has reached minimum operating temperature. (BACT for NO_x)

24. The owner/operator shall ensure that the Gas Turbines (S-1, S-3, S-5, & S-7) and HRSGs (S-2, S-4, S-6, & S-8) comply with requirements (a) through (h) under all operating scenarios, including duct burner firing 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 as NO_2) at P-1 (the combined exhaust point for S-1 Gas Turbine and S-2 HRSG after abatement by A-2 SCR System) shall not exceed 15.67 pounds per hour or 0.00731 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-2 (the combined exhaust point for S-3 Gas Turbine and S-4 HRSG after abatement by A-4 SCR System) shall not exceed 15.67 pounds per hour or 0.00731 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-3 (the combined exhaust point for S-5 Gas Turbine and S-6 HRSG after abatement by A-6 SCR System) shall not exceed 15.67 pounds per hour or 0.00731 lb/MM BTU (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated as NO_2) at P-4 (the combined exhaust point for S-7 Gas Turbine and S-8 HRSG after abatement by A-8 SCR System) shall not exceed 15.67 pounds per hour or 0.00731 lb/MM BTU (HHV) of natural gas fired. (PSD for NO_x)

    (b) The nitrogen oxide emission concentration at emission points P-1, P-2, P-3, and P-4 each shall not exceed 2.0 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-1, P-2, P-3, and P-4 each shall not exceed 19.08 pounds per hour or 0.0088 lb/MM BTU of natural gas fired, averaged over any rolling 3-hour period. (PSD for CO)

    (d) The carbon monoxide emission concentration at P-1, P-2, P-3, and P-4 each shall not exceed 4.0 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-1, P-2, P-3, and P-4 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-2, A-4, A-6, and A-8 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-2, A-4, A-6, and A-8 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-1, P-2, P-3, and P-4 shall be determined in accordance with permit part 34. (TRMP for NH_3)

(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-1, P-2, P-3, and P-4 each shall not exceed 4.42 pounds per hour or 0.00594 lb/MM BTU of natural gas fired. (BACT)

(g) Sulfur dioxide (SO_2) mass emissions at P-1, P-2, P-3, and P-4 each shall not exceed 2.0 pounds per hour or 0.00092 lb/MM BTU of natural gas fired. (BACT)

(h) Particulate matter (PM_{10}) mass emissions at P-1, P-2, P-3, and P-4 each shall not exceed 9 pounds per hour or 0.0048 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM_{10}) mass emissions at P-1, P-2, P-3, and P-4 each shall not exceed 12.75 pounds per hour or 0.00594 lb PM_{10}/MM BTU of natural gas fired when the HRSG duct burners are in operation. (BACT)

25. The owner/operator shall ensure that the regulated air pollutant mass emission rates from each of the Gas Turbines (S-1, S-3, S-5, and S-7) during a start-up does not exceed the limits established below. (PSD)

Gas Turbine Start-up Emission Rate Limits

	lb/hr	lb/start-up
NOx (as NO_2)	150	415.5
CO	662.5	1,180.5
POC (as CH_4)	45	83

26. The owner/operator shall not allow more than two Gas Turbines (S-1 & S-3, or S-5, & S-7) to be in start-up mode at any point in time. The owner/operator shall start-up additional gas turbines (S-1 & S-3 or S-5& S-7) only if both of the following requirements are met:

(a) 60 minutes has elapsed since the initiation of the start-up of the first pair of turbines
(b) the first pair of turbines are operating in compliance with the NOx and CO emission limitations of part 24.

(PSD)

27. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8), including emissions generated during Gas Turbine start-ups and shutdowns to exceed the following limits during any one hour:

(a) 331.3 pounds of NO_x (as NO_2) per hour
(b) 1,362.8 pounds of CO per hour
(PSD)

28. The owner/operator shall not allow total combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) and S-9 Fire Pump Diesel Engine, including emissions generated during Gas Turbine start-ups and shutdowns to exceed the following limits during any calendar day:

(a)	2,824.4 pounds of NO_x (as NO_2) per day	(CEQA)
(b)	6,284 pounds of CO per day	(PSD)
(c)	678.4 pounds of POC (as CH_4) per day	(CEQA)
(d)	1,224 pounds of PM_{10} per day (February 1 through October 31)	(PSD)
(e)	1,080 pounds of PM_{10} per day (November 1 through January 31)	(PSD)
(f)	192 pounds of SO_2 per day	(BACT)

29. The owner/operator shall not allow cumulative combined emissions from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) and S-9 Fire Pump Diesel Engine, including emissions generated during gas turbine start-ups and shutdowns to exceed the following limits during any consecutive twelve-month period:

(a)	249.85 tons of NO_x (as NO_2) per year	(Offsets)
(b)	335.66 tons of CO per year	(Cumulative Increase, PSD)
(c)	60.44 tons of POC (as CH_4) per year	(Offsets)
(d)	189.95 tons of PM_{10} per year	(Offsets)
(e)	29.55 tons of SO_2 per year	(Cumulative Increase)

30. The owner/operator shall not allow the maximum projected annual toxic air contaminant emissions (per part 33) from the Gas Turbines and HRSGs (S-1, S-2, S-3, S-4, S-5, S-6, S-7, and S-8) combined to exceed the following limits:

formaldehyde	17,657 pounds per year
benzene	732 pounds per year
Specified polycyclic aromatic hydrocarbons (PAHs)	6 pounds per year

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment to determine the total facility risk using the emission rates determined by source testing and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. The owner/operator shall submit the risk analysis 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 not result in a significant cancer risk, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

31. The owner/operator shall demonstrate compliance with parts 16 through 19, 24(a) through 24(d), and 25 through 29 by using properly operated and maintained continuous monitors (during all hours of operation including gas turbine 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-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7 & S-8 combined.
    (b) Oxygen (O_2) Concentration, Nitrogen Oxides (NO_x) Concentration, and Carbon Monoxide (CO) Concentration at exhaust points P-1, P-2, P-3, and P-4.
    (c) Ammonia injection rate at A-2, A-4, A-6, and A-8 SCR Systems

    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 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-1 & S-2 combined, S-3 & S-4 combined, S-5 & S-6 combined, and S-7 & S-8.
    (f) Corrected NO_x concentration, NO_x mass emission rate (as NO_2), corrected CO concentration, and CO mass emission rate at each of the following exhaust points: P-1, P-2, P-3, and P-4.

    For each source, source grouping, or exhaust point, the owner/operator shall record the parameters specified in parts 31(e) and 31(f) 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 eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined.
    (i) the average NO_x mass emission rate (as NO_2), CO mass emission rate, 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 eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected NO_x emission concentration, NO_x mass emission rate (as NO_2), corrected CO emission concentration, and CO mass emission rate 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 eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined.

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

32. To demonstrate compliance with parts 24(f), 24(g), 24(h), 25, 28(c) through 28(f), and 29(c) through 29(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 measured pursuant to part 31, actual Gas Turbine start-up times, actual Gas Turbine shutdown times, and CEC and District-approved emission factors developed pursuant to souce testing under part 35 to calculate these emissions. The owner/operator shall present the calculated emissions in the following format:

(a) For each calendar day, POC, PM_{10}, and SO_2 emissions, summarized for each power train (Gas Turbine and its respective HRSG combined) and all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined

(b) on a daily basis, the cumulative total POC, PM_{10}, and SO_2 mass emissions, for each year for all eight sources (S-1, S-2, S-3, S-4, S-5, S-6, S-7, & S-8) combined

(Offsets, PSD, Cumulative Increase)

33. To demonstrate compliance with Part 30, the owner/operator shall calculate and record on an annual basis the maximum projected annual emissions of: Formaldehyde, Benzene, and Specified PAH's. The owner/operator shall calculate the maximum projected annual emissions using the maximum annual heat input rate of 62,152,696 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-1, S-3, S-5, and S-7 Gas Turbines and/or S-2, S-4, S-6, and S-8 Heat Recovery Steam Generators. If the highest emission factor for a given pollutant occurs during minimum-load turbine operation, a reduced annual heat input rate may be utilized to calculate the maximum projected annual emissions to reflect the reduced heat input rates during gas turbine start-up and minimum-load operation. The reduced annual heat input rate shall be subject to District review and approval. (TRMP)

34. Prior to the end of the commissioning period for the TPP, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, P-3, or P-4 to determine the corrected ammonia (NH_3) emission concentration to determine compliance with part 24(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-2, A-4, or A-6 SCR System ammonia injection rate, and the corresponding NH_3 emission concentration at emission point P-1, P-2, P-3, or P-4. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum and full load, and steam injection power augmentation mode) to establish the range of ammonia injection rates necessary to achieve

NO_x emission reductions while maintaining ammonia slip levels. The owner/operator shall repeat the source testing on an annual basis thereafter. Ongoing compliance with part 24(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (TRMP)

35. Prior to the end of the commissioning period for the TPP and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1, P-2, P-3, and P-4 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 Parts 24(a), 24(b), 24(c), 24(d), 24(f), 24(g), and 24(h) and while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Parts 24(c) and (d), and to verify the accuracy of the continuous emission monitors required in part 31. 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. The owner/operator shall conduct the particulate matter (PM_{10}) source tests during the period of November 1 through January 31 of each year to verify compliance with part 28(e). The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (BACT, offsets)

36. 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. The owner/operator shall submit the source test results to the District and the CEC CPM within 45 days of conducting the tests. (BACT)

37. Prior to the end of the commissioning period for the TPP and on a biennial basis (once every two years) thereafter, the owner/operator shall conduct a District-approved source test on exhaust point P-1, P-2, P-3, or P-4 while the Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum allowable operating rates to demonstrate compliance with Part 30. The owner/operator shall also test the gas turbine while it is operating at minimum load. If three consecutive biennial source tests demonstrate that the annual emission rates calculated pursuant to part 30 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	≤	6.7 pounds/year
Formaldehyde	≤	33 pounds/year
Specified PAHs	≤	0.044 pounds/year

(TRMP)

38. The owner/operator shall not allow the total combined sulfuric acid mist (SAM) emissions from S-1 through S-8 to exceed 7 tons totaled over any consecutive twelve month period. The owner/operator shall calculate the SAM emission rate using the total heat input for the sources and the highest results of any source testing conducted pursuant to part 39. If this SAM mass emission limit is exceeded, the owner/operator must utilize air dispersion modeling to determine the impact (in $\mu g/m^3$) of the sulfuric acid mist emissions pursuant to Regulation 2-2-306. (PSD)

39. Prior to the end of the commissioning period for the TPP and on a semi-annual basis (twice per year) thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-1 through P-4 while each gas turbine and HRSG duct burner is operating at maximum heat input rates to demonstrate compliance with the SAM emission rates specified in part 38. The owner/operator shall test for (as a minimum) SO_2, SO_3, and H_2SO_4. After acquiring one year of source test data on these sources, the owner/operator may petition the District to reduce the test frequency to an annual basis if test result variability is sufficiently low as determined by the District. The owner/operator shall submit the source test results to the District and the CEC CPM within 60 days of conducting the tests. (PSD)

40. The owner/operator of the TPP 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)

41. The owner/operator of the TPP 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)

42. The owner/operator of the TPP 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)

43. The owner/operator shall ensure that the stack height of emission points P-1, P-2, P-3, and P-4 is each at least 200 feet above grade level at the stack base. (PSD, TRMP)

44. The Owner/Operator of TPP 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 comply with the District Manual of Procedures, Volume IV, Source Test Policy and Procedures, and shall be subject to BAAQMD review and approval. (Regulation 1-501)

45. Within 180 days of the issuance of the Authority to Construct for the TPP, the Owner/Operator shall contact the BAAQMD Technical Services Division regarding requirements for the continuous emission monitors, sampling ports, platforms, and source tests required by parts 31, 34, 35, 37, and 51. The owner/operator shall conduct all source testing and monitoring in accordance with the BAAQMD Manual of Procedures. (Regulation 1-501)

46. Prior to the issuance of the BAAQMD Authority to Construct for the Tesla Power Project, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 287.328 tons/year of Nitrogen Oxides, 69.5 tons/year of Precursor Organic Compounds, and 189.95 tons/year of PM_{10} or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2) are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

47. Prior to the start of construction of the Tesla Power Project, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 287.328 tons/year of Nitrogen Oxides, 69.5 tons/year of Precursor Organic Compounds, and 189.95 tons/year of PM_{10} or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2. (Offsets, CEC)

48. Pursuant to BAAQMD Regulation 2, Rule 6, section 404.1, the owner/operator of the TPP shall submit an application to the BAAQMD for a major facility review permit within 12 months of completing construction as demonstrated by the first firing of any gas turbine or HRSG duct burner. (Regulation 2-6-404.1)

49. Pursuant to 40 CFR Part 72.30(b)(2)(ii) of the Federal Acid Rain Program, the owner/operator of the Tesla Power Project shall submit an application for a Title IV operating permit to the BAAQMD at least 24 months before operation of any of the gas turbines (S-1, S-3, S-5, or S-7) or HRSGs (S-2, S-4, S-6, or S-8). (Regulation 2, Rule 7)

50. The owner/operator shall ensure that the Tesla Power Project complies with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

51. The owner/operator shall take monthly samples of the natural gas combusted at the TPP. The samples shall be analyzed for sulfur content using District-approved laboratory methods. 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. (cumulative increase)

Permit Conditions for Cooling Towers

52. The owner/operator shall properly install and maintain the cooling towers to minimize drift losses. The owner/operator shall equip the cooling towers 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 1,878 ppmw (mg/l). The owner/operator shall sample and test the cooling tower water at least once per day to verify compliance with this TDS limit. (PSD)

53. 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 Tesla Power Project, 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. Within 60 days of the initial operation of the cooling tower, the owner/operator shall perform an initial performance source test to determine the PM_{10} emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in part 51. The CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform source tests to verify continued compliance with the vendor-guaranteed drift rate specified in part 51. (PSD)

Permit Conditions for S-9 Fire Pump Diesel Engine

54. S-9 Fire Pump Diesel Engine is subject to the requirements of Regulation 9, Rule 1 ("Sulfur Dioxide"), and the requirements of Regulation 6 ("Particulate and Visible Emissions"). The engine may be subject to other District regulations, including Regulation 9, Rule 8 ("NOx and CO from Stationary Internal Combustion Engines") in the future.
(Regulation 9, Rule 1; Regulation 6)

55. The owner/operator shall ensure that S-9 is operated for no more than a total of 26 hours in any consecutive 12-month period for the purpose of reliability-related activities as defined by Regulation 9-8-232. (Offsets, BACT)

56. The owner/operator may cause S-9 to operate for an unlimited amount of time for the purpose of providing power for the emergency pumping of water. (Regulation 9-8-330.1)

57. The owner/operator shall equip S-9 with a non-resettable totalizing counter which records hours of operation. (cumulative increase)

58. The owner/operator shall ensure that the sulfur content of all diesel fuel combusted at S-9 does not exceed 0.05% by weight. (TRMP, TBACT)

59. The owner/operator shall ensure that S-9 Fire Pump Diesel Engine shall achieve the following emission rates:

NO_x (as NO_2) 6.9 g/bhp-hr
CO 1.75 g/bhp-hr
POC 1.5 g/bhp-hr
PM10 0.15 g/bhp-hr
(BACT, cumulative increase)

60. Within 60 days of the initial start-up of S-9, the owner/operator shall test the engine to determine the NOx, CO, PM_{10}, and POC emission rates to verify compliance with part 59. The owner/operator shall utilize the following test methods for each pollutant as indicated below.

    (a) NOx source testing shall be in accordance with the District's Manual of Procedures, Volume IV, ST-13A or B
    (b) CO source testing shall be in accordance with the District's Manual of Procedures, Volume IV, ST-6
    (c) POC source testing shall be in accordance with the District's Manual of Procedures, Volume IV, ST-7
    (d) PM_{10} testing shall be in accordance with California Air Resources Board (CARB) test method 17.

    (BACT, TRMP)

61. If the Merged Stack Parameter (M) of the final specified fire pump diesel engine is less than 2.13E07, then the owner/operator must perform a revised health risk assessment for the S-9 diesel engine particulate emissions. The health risk assessment will be subject to District review and approval. The Merged Stack Parameter (M) is defined as follows:

    M = hVT/Q

    where, h = stack height (in meters)
    V = stack gas volumetric flow rate (m^3/s) at full load
    T = stack gas temperature (degrees Kelvin) at full load
    Q = diesel particulate emission rate (g/s) at full load

    (TRMP)

62. The owner/operator shall maintain the following monthly records in a District-approved log for at least 5 years and make such records and logs available to the District upon request:

    a) total hours of operation for the purpose of reliability-related activities for S-9 and a description of the reliability-related activity
    b) total hours of operation for the purpose of the emergency pumping of water for S-9 and a description of the emergency condition
    c) fuel sulfur content

    (cumulative increase)

VI Recommendation

The Exective Officer/APCO of the BAAQMD has concluded that the proposed Tesla Power Project 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-1 Combustion Gas Turbine #1, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-2 Heat Recovery Steam Generator #1, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-1 Oxidation Catalyst and A-2 Selective Catalytic Reduction System

S-3 Combustion Gas Turbine #2, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-4 Heat Recovery Steam Generator #2, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-3 Oxidation Catalyst and A-4 Selective Catalytic Reduction System

S-5 Combustion Gas Turbine #3, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-6 Heat Recovery Steam Generator #3, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-7 Combustion Gas Turbine #4, General Electric PG 7241 (7FA); 1875.5 MM BTU per hour, equipped with dry low-NO_x Combustors, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-8 Heat Recovery Steam Generator #4, equipped with dry low-NO_x Duct Burners, 272.2 MM BTU per hour, abated by A-5 Oxidation Catalyst and A-6 Selective Catalytic Reduction System

S-9 Fire Pump Diesel Engine, Make and Model to be determined, 368 bhp, 19 gallons per hour

Pursuant to District Regulation 2-3-404, this document has satisfied the public notice, public comment, and public inspection requirements of Regulation 2-2-406 and 2-2-407. Accordingly, a notice inviting written public comment was published on August 15, 2002 in the Contra Costa

Times, a newspaper of general circulation in the area of the proposed Tesla Power Project. The public inspection and comment period ended on September 16, 2002. All written comments received were responded to in writing.

William C. Norton
Executive Officer/Air Pollution Control Officer
Bay Area Air Quality Management District
939 Ellis Street
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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]:	8600 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 reflect 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		
	lb/MM BTU	lb/hr @ 17°F	lb/hr @ 62°F	lb/MM BTU	lb/hr @ 17°F	lb/hr @ 62°F
Nitrogen Oxides (as NO_2)	0.00731[a]	13.71	12.84	0.00731[a]	15.67	14.76
Carbon Monoxide	0.0088[b]	16.7	15.46	0.0088[b]	19.08	17.77
Precursor Organic Compounds	0.00126	2.36	2.2	0.00206	4.42	4.25
Particulate Matter (PM_{10})	0.00525	9.84	9.84	0.00594	12.75	12.75
Sulfur Dioxide	0.00092	1.75	1.62	0.00092	2	1.86
Sulfuric Acid Mist (H_2SO_4)	0.00107	2	1.88	0.00107	2.82	2.16

[a]based upon the permit condition stack gas emission limit of 2.0 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 Selective Catalytic Reduction Systems with ammonia injection

[b]based upon the permit condition stack gas emission limit of 4 ppmvd CO @ 15% O_2 that reflects the use of oxidation catalysts

REGULATED AIR POLLUTANTS

NITROGEN OXIDE EMISSION FACTORS

Gas Turbine and Heat Recovery Steam Generator Combined

The combined NO_x emissions (as NO_2) from the GT and HRSG will be limited to 2.0 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:

(2.0 ppmvd)(20.95 - 0)/(20.95 - 15) = 7.04 ppmv NO_x, dry @ 0% O_2

($7.04/10^6$)(1 lbmol/385.3 dscf)(46.01 lb NO_2/lbmol)(8600 dscf/MM BTU)

= 0.00723 lb NO_2/MM BTU

The NO_2 mass emission rate based upon the maximum firing rate of the gas turbine alone @ 17°F is calculated as follows:

(0.00723 lb/MM BTU)(1,875.5 MM BTU/hr) = **13.56 lb NO_2/hr**

The applicant calculated a slightly higher mass emission rate of **13.71 lb NO_2/hr.**

This converts to an emission factor of:

(13.71 lb/hr)/(1875.5 MM BTU/hr) = **0.00731 lb NO_2/MM BTU**

The NO_2 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of the gas turbine and HRSG is:

(0.00723 lb/MM BTU)(2,147.7 MM BTU/hr) = **15.53 lb NO_2/hr**

The applicant calculated a slightly higher mass emission rate of **15.67 lb NO_2/hr.**

The annual average NO_2 mass emission rate based upon the maximum firing rate of the gas turbine alone at the annual average temperature of 62°F is:

(0.00731 lb/MM BTU)(1,756.7 MM BTU/hr) = **12.84 lb NO_2/hr**

The annual average NO_2 mass emission rate when duct burner firing occurs is based upon the maximum combined firing rate of 2,018.9 MM BTU/hr and is:

(0.00731 lb/MM BTU)(2,018.9 MM BTU/hr) = **14.76 lb NO_2/hr**

CARBON MONOXIDE EMISSION FACTORS

Gas Turbine and Heat Recovery Steam Generator Combined

The combined CO emissions from the GT and HRSG duct burner will be limited by permit condition to a maximum controlled CO emission concentration of 4 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:

$(4\ ppmv)(20.95 - 0)/(20.95 - 15) = 14.08\ ppmv$, dry @ 0% O_2

$(14.08/10^6)$(lbmol/385.3 dscf)(28 lb CO/lbmol)(8600 dscf/MM BTU)

= 0.0088 lb CO/MM BTU

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

(0.0088 lb/MM BTU)(1,875.5 MM BTU/hr) = **16.5 lb CO/hr @ 17°F**

The applicant calculated a slightly higher mass emission rate of **16.7 lb CO/hr @ 17°F**

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

(0.0088 lb/MM BTU)(2,147.7 MM BTU/hr) = **18.9 lb CO/hr**

The applicant calculated a slightly higher mass emission rate of **19.08 lb CO/hr @ 17°F**

The annual average CO mass emission rate based upon the maximum firing rate of the gas turbine alone at the annual average temperature of 62°F (1,756.7 MM BTU/hr) is calculated as follows:

(0.0088 lb/MM BTU)(1,756.7 MM BTU/hr) = **15.46 lb CO/hr**

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

(0.0088 lb/MM BTU)(2,018.9 MM BTU/hr) = **17.77 lb CO/hr**

PRECURSOR ORGANIC COMPOUND (POC) EMISSION FACTORS

Gas Turbine

Midway Power estimates a maximum POC (non-methane, non-ethane hydrocarbon) stack gas emission concentration of 1 ppmv @ 15% O_2 for full load operation of the gas turbine alone. The emission factor corresponding to this emission concentration is calculated as follows:

$(1\ ppmv)(20.95 - 0)/(20.95 - 15) = 3.52\ ppmv$, dry @ 0% O_2

$(3.52/10^6)$(lb-mol/385.3 dscf)(16 lb CH_4/lb-mol)(8600 dscf/MM BTU)

= 0.00126 lb POC/MM BTU

The POC mass emission rate based upon the maximum firing rate @ 17°F is:

POC = (0.00126 lb/MM BTU)(1,875.5 MM BTU/hr) = **2.36 lb/hr**

The applicant has calculated a slightly lower POC emission rate of **2.24 lb/hr**.

The POC mass emission rate based upon the maximum firing rate @ 62°F is:

POC = (0.00126 lb/MM BTU)(1,756.7 MM BTU/hr) = **2.2 lb/hr**

The applicant has calculated a slightly lower POC emission rate of **2.1 lb/hr**.

Gas Turbine and Heat Recovery Steam Generator Combined

Midway Power estimates a maximum POC (non-methane, non-ethane hydrocarbon) stack gas emission concentration of 1.64 ppmv @ 15% O_2 for full load operation of the gas turbine with duct burner firing and steam injection power augmentation.

The emission factor corresponding to this emission concentration is calculated as follows:

(1.64 ppmv)(20.95 - 0)/(20.95 - 15) = 5.77 ppmv, dry @ 0% O_2

($5.77/10^6$)(lb-mol/385.3 dscf)(16 lb CH_4/lb-mol)(8600 dscf/MM BTU) = **0.00206 lb POC/MM BTU**

The POC mass emission rate based upon the maximum firing rate @ 17°F is:

POC = (0.00206 lb/MM BTU)(2,147.7 MM BTU/hr) = **4.42 lb/hr**

The applicant has calculated a slightly lower POC emission rate of **4.25 lb/hr**.

The POC mass emission rate based upon the maximum firing rate @ 62°F is:

POC = (0.00206 lb/MM BTU)(2,018.9 MM BTU/hr) = **4.16 lb/hr**

The applicant has calculated a slightly lower POC emission rate of **4 lb/hr**.

PARTICULATE MATTER (PM_{10}) EMISSION FACTORS

Gas Turbine

Based upon vendor specifications, Midway Power has proposed a maximum PM_{10} emission rate of 9.84 lb/hr at maximum load for each gas turbine @ 17°F.

The corresponding PM_{10} emission factor is therefore:

(9.84 lb PM_{10}/hr)/(1,875.5 MM BTU/hr) = **0.00525 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.

The following worst-case stack gas characteristics (with respect to grain loading) during full load operation w/o duct burner firing occur at the lowest expected typical ambient temperature of 45°F.

PM_{10} mass emission rate:	9.84 lb/hr
exhaust gas flow rate:	887,080 acfm @ 13.42% O_2 and 189°F
moisture content:	8.78% by volume

Converting flow rate to standard conditions:

(887,080 acfm)(70 + 460 °R/189 + 460 °R)(1 – 0.0878) = 660,821 dscfm

Converting to grains/dscf:

(9.84 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(660,821 dscfm) = 0.0017 gr/dscf

Converting to 6% O_2 basis:

(0.0017 gr/dscf)[(20.95 - 6)/(20.95 – 13.42)] = 0.0034 gr/dscf @ 6% O_2

Gas Turbine and HRSG Combined

Midway Power has estimated a maximum PM_{10} emission rate of 12.75 lb/hr at the maximum combined firing rate of 2,147.7 MM BTU/hr during duct burner firing based upon vendor specifications and assumptions regarding the formation of sulfate particulates.

The corresponding PM_{10} emission factor is therefore:

(12.75 lb PM_{10}/hr)/(2,147.7 MM BTU/hr) = **0.00594 lb PM_{10}/MM BTU**

The following stack data will be used to calculate the grain loading for full load turbine operation with duct burner firing at standard conditions to determine compliance with BAAQMD Regulation 6-310.3.

The following worst-case stack gas characteristics (with respect to grain loading) during full load with duct burner firing occur at the highest expected "typical" ambient temperature of 112°F.

PM_{10} mass emission rate:	12.64 lb/hr (applicant's estimate)
typical flow rate:	938,147 acfm @ 9.88% O_2 and 186°F
typical moisture content:	9.6% by volume

Converting flow rate to standard conditions:

(938,147 acfm)(70 + 460 °R/186 + 460 °R)(1 - 0.096) = 696,445 dscfm

Converting to grains/dscf:

(12.64 lb PM_{10}/hr)(1 hr/60 min)(7000 gr/lb)/(696,445 dscfm) = 0.0021 gr/dscf

Converting to 6% O_2 basis:

(0.0021 gr/dscf)[(20.95 - 6)/(20.95 – 9.6)] = 0.0027 gr/dscf @ 6% O_2

SULFUR DIOXIDE EMISSION FACTORS

Gas Turbine & Heat Recovery Steam Generator

The SO_2 emission factor is based upon an expected maximum natural gas sulfur content of 3300 gr/10^6 scf of natural gas and a higher heating value of 1022 BTU/scf.

The sulfur emission factor is calculated as follows:

(3300 gr/10^6 scf)(2 lb SO_2/lb S)(scf/1022 BTU)(1 lb/7000 gr)(10^6 BTU/MM BTU)

= **0.00092 lb SO_2/MM BTU**

This is converted to an emission concentration as follows:

(0.00092 lb SO_2/MM BTU)(385.3 dscf/lb-mol)(lb-mol/64.06 lb SO_2)(10^6 BTU/8600 dscf)

= 0.64 ppmvd SO_2 @ 0% O_2

which is equivalent to:

(0.64 ppmvd)(20.95 - 15)/20.95 = 0.18 ppmv SO_2, dry @ 15% O_2

The SO_2 mass emission rate for the gas turbine with duct burner firing at 17°F is:

(0.00092 lb SO_2/MM BTU)(2,147.7 MM BTU/hr) = **2 lb/hr**

The SO_2 mass emission rate for the gas turbine alone at 17°F is:

(0.00092 lb SO_2/MM BTU)(1,875.5 MM BTU/hr) = **1.75 lb/hr**

The SO_2 mass emission rate for the gas turbine with duct burner firing at 62°F is:

(0.00092 lb SO_2/MM BTU)(2,018.9 MM BTU/hr) = **1.86 lb/hr**

The SO_2 mass emission rate for the gas turbine alone at 62°F is:

(0.00092 lb SO_2/MM BTU)(1,756.7 MM BTU/hr) = **1.62 lb/hr**

SULFURIC ACID MIST EMISSION FACTORS

Gas Turbine & Heat Recovery Steam Generator

The H_2SO_4 emission factor is based upon an expected maximum natural gas sulfur content of 3300 gr/10^6 scf of natural gas and a higher heating value of 1022 BTU/scf. To be conservative, it is assumed that all of the sulfur contained in the fuel is converted to sulfuric acid mist.

(3300 gr/10^6 scf)(98 lb H_2SO_4/32 lb S)(scf/1022 BTU)(1 lb/7000 gr)(10^6 BTU/MM BTU)

= **0.00141 lb SO_2/MM BTU**

The H_2SO_4 mass emission rate for the gas turbine with duct burner firing at 17°F is:

(0.00141 lb SO_2/MM BTU)(2,147.7 MM BTU/hr) = **3.03 lb/hr**

The H_2SO_4 mass emission rate for the gas turbine alone at 17°F is:

(0.00141 lb SO_2/MM BTU)(1,875.5 MM BTU/hr) = **2.64 lb/hr**

The H_2SO_4 mass emission rate for the gas turbine with duct burner firing at 62°F is:

(0.00141 lb SO_2/MM BTU)(2,018.9 MM BTU/hr) = **2.46 lb/hr**

The H_2SO_4 mass emission rate for the gas turbine alone at 62°F is:

(0.00141 lb SO_2/MM BTU)(1,756.7 MM BTU/hr) = **2.14 lb/hr**

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]	1.37E-01
Acrolein	1.89E-02
Ammonia[b]	6.75
Benzene[c]	1.33E-02
1,3-Butadiene[c]	1.27E-04
Ethylbenzene	1.79E-02
Formaldehyde[c]	1.10E-01
Hexane	2.59E-01
Naphthalene	1.66E-03
Propylene	7.71E-01
Propylene Oxide[c]	4.78E-02
Toluene	7.10E-02
Xylene	2.61E-02
Total PAHs	1.06E-04

[a]California Air Toxics Emission Factors (CATEF) Database as compiled by California Air Resources Board under the Air Toxics Hotspot Program; mean values

[b]based upon maximum allowable ammonia slip of 5 ppmv, dry @ 15% O_2 for A-2, A-4, A-6, and A-8 SCR Systems

[c]carcinogenic compound

Table A-3 TAC Emission Factors for Each 11-Cell Cooling Tower

Toxic Air Contaminant	Maximum Concentration in Cooling Tower Return Water (ppmw)	Emission Factor[a] (lb/hr)
Arsenic[b]	0.04	1.48E-05
Bromide	4.2	1.56E-03
Cadmium[b]	0.08	2.96E-05
Trivalent chromium	0.05	1.85E-05
Copper	0.1	3.70E-05
Fluoride	1.8	6.67E-04
Mercury	0.016	5.93E-06
Nickel	0.04	1.48E-05
Manganese	0.14	5.19E-05
Sulfate	860	3.19E-01
Zinc	0.18	6.66E-05

[a]based upon maximum drift rate of 0.0005% and operation of cooling tower at maximum water circulation rate of 148,110 gallons per minute; for example:

Arsenic $= (0.04/10^6)(0.000005)(148{,}110\ \text{gal/min})(60\ \text{min/hr})(8.337\ \text{lb/gal})$
$= 1.48\text{E-}05\ \text{lb/hr}$

[b]carcinogenic compound

AMMONIA SLIP EMISSION FACTORS

Combustion Gas Turbine & Heat Recovery Steam Generator

Each Gas Turbine/HRSG power train will exhaust through a common stack and be subject to an ammonia slip limit of 5 ppmvd @ 15% O_2.

NH_3 emission concentration limit:	5 ppmvd @ 15% O_2
Typical dry gas flow rate (w/duct burner):	898,057 acfm, dry @ 12.62% O_2 by volume
Maximum dry gas flow rate (w/duct burner):	973,165 acfm, dry @ 12.76% O_2 by volume

Correcting ammonia concentration to actual oxygen content at full load with duct burner firing:

(5 ppmvd)(20.95 – 12.76)/(20.95 – 15) = 6.88 ppmvd @ 12.76% O_2

The maximum ammonia mass emission rate at full load with duct burner firing is therefore:

(6.88 ppmvd/10^6)(973,165 dscfm)(60 min/hr)(lb-mol/471.1 dscf)(17 lb NH_3/lb-mol)

= 14.5 lb NH_3/hr

Based upon the maximum combined heat input for a gas turbine/HRSG of 2,147.7 MM BTU/hr @ 17°F, this mass emission rate converts to the following emission factor:

(14.5 lb NH_3/hr)/(2,147.7 MM BTU/hr) **= 0.00675 lb NH_3/MM BTU**
= 6.75 lb NH_3/MM scf

Correcting ammonia concentration to actual oxygen content at full load with duct burner firing under typical operating conditions:

(5 ppmvd)(20.95 – 12.62)/(20.95 – 15) = 7 ppmvd @ 12.62% O_2

The ammonia mass emission rate at full load without duct burner firing is therefore:

(7 ppmvd/10^6)(898,057 dscfm)(60 min/hr)(lb-mol/471.1 acf)(17 lb NH_3/lbmol)

= 13.6 lb NH_3/hr

Based upon the maximum heat input for a gas turbine of 2,018.9 MM BTU/hr @ 62°F, this mass emission rate converts to the following emission factor:

(13.6 lb NH_3/hr)/(2,018.9 MM BTU/hr) = **0.00675 lb NH_3/MM BTU**
= **6.75 lb NH_3/MM scf**

Table A-4
Regulated Air Pollutant Emission Factors for Fire Pump Diesel Engine

Pollutant	Emission Factor	
	g/bhp-hr	lb/hr[b]
Nitrogen Oxides (as NO_2)	6.9[a]	5.6
Carbon Monoxide	2.75[a]	2.23
Precursor Organic Compounds	1.5[a]	1.2
Particulate Matter (PM_{10})	0.15[a]	0.12
Sulfur Dioxide	0.93	0.75

[a]per District BACT Guideline 96.1.2

[b]based upon maximum rated output of 368 bhp

Table A-5
Toxic Air Contaminant Emission Factors for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor[a] (lb/MM BTU)
Benzene	9.33E-04
Toluene	4.09E-04
Xylenes	2.85E-04
Propylene	2.58E-03
1,3-Butadiene	3.91E-05
Formaldehyde	1.18E-03
Acetaldehyde	7.67E-04
Acrolein	9.25E-05
Total PAHs	1.68E-04
Diesel Particulate	0.16 g/bhp-hr

[a]AP-42 Table 3.3-2, "Speciated Organic Compound Emission Factors for Uncontrolled Diesel Engines"

Appendix B

Emission Calculations

Individual and combined heat input rate limits for the Gas turbines and HRSGs are shown 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
	@ 17°F	@ 62°F		
S-1, S-3, S-5, and S-7 Gas Turbines	1,875.5	1,756.7	45,190.4[a]	5,126,929[b]
S-1 CTG and S-2 HRSG (combined) S-3 CTG and S-4 HRSG (combined) S-5 CTG and S-6 HRSG (combined) S-7 CTG and S-8 HRSG (combined)	2,147.7[c]	2,018.9[c]	51,544.8[d]	10,619,414[e]
Turbines and HRSGs combined	8,590.8	8,075.6	206,417.6[f]	62,985,372

[a]based upon 24 hour per day operation without duct burner firing @ 17°F

[b]based upon 2,800 hours of operation at full load, without duct burner firing @ 62°F

[c]maximum combined firing rate for each gas turbine and corresponding HRSG duct burner

[d]based upon maximum duct burner firing of 24 hours per day @ 17°F

[e]based upon maximum annual duct burner firing of 5,260 hr/year-HRSG @ 62°F; calculated as:

(5,260 hr/yr)(2,018.9 MM BTU/hr) = 10,619,414 MM BTU/year

[f]based upon 24 hr/day duct burner firing for all four power trains @17°F

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

The maximum nitrogen oxide, carbon monoxide, and precursor organic compound mass emission rates from a gas turbine occur during start-up periods. The PM_{10} and sulfur dioxide emissions are a function only of fuel use rate and do not exceed typical full load emission rates during start-up. The NO_x, CO, and UHC (POC) emission rates shown in Table B-3 are Midway Power estimates and are based upon gas turbine vendor estimates.

Table B-2
Gas Turbine Start-Up Emission Rates
(lb/start-up)

Pollutant	Cold Start-Up[a]		Hot Start-Up[b]		Warm Start-Up[c]	
	lb/hr	lb/start-up	lb/hr	lb/start-up	lb/hr	lb/start-up
NO_x (as NO_2)	150	415.5	109.5	116.2	131.5	225.8
CO	400	901.5	350	355.9	662.5	1180.25
UHC (as CH_4)	32	83	35	35.3	45	79
PM_{10}[d]	12.75	63.75	12.75	19.1	12.75	38.25
SO_x (as SO_2)[e]	2	10	2	3	2	6

[a]cold start not to exceed five hours; by definition, occurs after turbine has been inoperative for at least 48 hours

[b]hot start not to exceed 90 minutes; by definition, occurs within 8 hours of a shutdown

[c]warm start not to exceed 3 hours; by definition occurs between 8 and 48 hours of a shutdown

[d]as a conservative estimate, based upon full load emission factor of 0.0058 lb PM_{10}/MM BTU and maximum heat input rate of 1,875.5 MM BTU/hr

[e]based upon full load emission factor of 0.0007 lb SO_2/MM BTU and maximum heat input rate of 1,875.5 MM BTU/hr

After considering source test data of the Los Medanos Energy Center gas turbines, it is assumed that turbine shutdown emission rates for NO_x, CO, and POC do not exceed full load emission rates. **Table B-3** is a comparison of Tesla baseload and shutdown emission rate estimates versus turbine shutdown emission rates based upon source test data.

Table B-3 Gas Turbine Shutdown Emission Rates

Pollutant	Baseload Emission Rate (lb/hr)[a]	Shutdown Emission Rate (lb/shutdown)	Los Medanos Energy Center Source Test Results[b]	
			lb/hr	lb/shutdown
NO_x (as NO_2)	15.67	50	39.5	16.86
CO	18.9	175	11.9	5.75
UHC (as CH_4)	4.42	17	5.2	5.2

[a]TPP emission rates for gas turbine w/duct burner firing

[b]highest of two G.E. Frame 7F turbines; testing dates July, August 2002

B-2.0 Operating Scenarios and Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

The Gas Turbine/HRSG air pollutant emission rates (except for NO_x) shown in **Table B-4** 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.

- 2,800 hours of baseload (100% load) operation per year for each gas turbine w/o duct burner firing
- 5,260 hours of baseload operation per gas turbine per year with duct burner firing
- 27 hot start-ups per gas turbine per year (90 minutes/start-up)
- 6 warm start-ups per gas turbine per year (180 minutes/start-up)
- 12 cold start-ups per gas turbine per year (300 minutes/start-up)
- 45 shutdowns per gas turbine per year (30 minutes/shutdown)

Table B-4 Maximum Annual Regulated Air Pollutant Emissions for Gas Turbines and HRSGs

Source (Operating Mode)	NO_2 (lb/yr)	CO (lb/yr)	POC (lb/yr)	PM_{10} (lb/yr)	SO_2 (lb/yr)	H_2SO_4 (lb/yr)
S-1, S-3, S-5, & S-7 Gas Turbines (108 total 1.5-hr hot start-ups)	12,549.6	38,437.2	3,812.4	2,062.8	324	324
S-1, S-3, S-5, & S-7 Gas Turbines (24 total 3-hr warm start-ups)	5,419.2	28,326	1,896	918	144	144
S-1, S-3, S-5, & S-7 Gas Turbines (48 total 5-hr cold start-ups)	19,944	43,272	4,464	3,060	480	480
S-1, S-3, S-5, & S-7 Gas Turbines (11,200 total hours @ 1,756.7 MM BTU/hr; 62°F)	143,808	173,152	24,640	100,800	18,144	21,056
S-1 Gas Turbine & S-2 HRSG S-3 Gas Turbine & S-4 HRSG S-5 Gas Turbine & S-6 HRSG S-7 Gas Turbine & S-8 HRSG (21,040 total hours w/duct burner firing @ 2,018.9 MM BTU/hr; 62°F)	310,550.4	373,880.8	89,420	268,260	39,134.4	45,446.4
S-1, S-3, S-5, & S-7 Gas Turbines (180 total 30-minute shutdowns)	9000	31,500	3,060	885.6	145.8	169.2
Total Emissions (lb/yr)	501,271.2	688,568	127,292.4	375,986.4	58,372.2	67,619.6
(ton/yr)	**250.636**	**344.284**	**63.646**	**187.993**	**29.186[a]**	**33.810[a]**

[a]represents worst-case emission rates assuming that all fuel-bound sulfur is converted to the compound indicated; it is not physically possible for the emission rates of each compound to reach these levels simultaneously

B-3.0 Fire Pump Diesel Engine Emissions

Table B-5 Regulated Air Pollutant Emissions for Fire Pump Diesel Engine

Pollutant	Emission Factor		Annual Emissions[a]	
	g/bhp-hr	lb/hr	lb/yr	ton/yr
Nitrogen Oxides (as NO_2)	6.9	5.6	145.6	0.073
Carbon Monoxide	2.75	2.23	58	0.029
Precursor Organic Compounds	1.5	1.2	31.2	0.016
Particulate Matter (PM_{10})	0.15	0.12	3.1	0.002
Sulfur Dioxide	0.93	0.75	19.5	0.01

[a]based upon 26 hours of operation per year for testing and maintenance and maximum rated output of 368 bhp

Table B-6 Worst-Case Toxic Air Contaminant Emissions for Fire Pump Diesel Engine

Toxic Air Contaminant	Emission Factor (lb/MM BTU)	Annual Emissions[a] (lb/yr)
Benzene	9.33E-04	0.124
Toluene	4.09E-04	0.054
Xylenes	2.85E-04	0.04
Propylene	2.58E-03	0.34
1,3-Butadiene	3.91E-05	0.005
Formaldehyde	1.18E-03	0.16
Acetaldehyde	7.67E-04	0.1
Acrolein	9.25E-05	0.01
Total PAHs	1.68E-04	0.02
Diesel particulate	0.13 lb/hr	6.5

[a]based upon assumed maximum fuel use rate of 19 gal/hr (2.66 MM BTU/hr) and maximum 50 operating hours per year; actual emissions will be less since allowable discretionary use has be reduced to 26 hours per year

B-4.0 Cooling Tower PM_{10} Emissions

Cooling tower circulation rate: 148,110 gpm
maximum total dissolved solids: 1878 ppmw
Drift Rate: 0.0005 %

Water mass flow rate: (148,110 gal/min)(60 min/hr)(8.34 lb/gal) = 74,114,244 lb/hr
Cooling Tower Drift: (74,114,244 lb/hr)(0.000005) = 370.57 lb/hr

PM_{10} = (1878 ppmw)(370.57 lb/hr)/(10^6)
= 0.7 lb/hr-tower
= 16.8 lb/day-tower (24 hr/day operation)
= 6,132 lb/yr-tower (8,760 operating hours per year)
= 3.066 ton/yr-tower

PM_{10} emission rate per cell:

(6,132 lb/yr-tower)(tower/11 cells)(yr/8760 hr) = 0.0636 lb/hr-cell
= 0.008 g/s-cell

B-5.0 Worst-Case Toxic Air Contaminant (TAC) Emissions

The maximum toxic air contaminant emissions resulting from the combustion of natural gas at the S-1, S-3, S-5, & S-7 Gas Turbines and S-2, S-4, S-6, & S-8 HRSGs are summarized in **Table B-7**. 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 14,165,796 MM BTU per year (13,753.2 MM scf/yr based upon a fuel HHV of 1030 BTU/scf) for each gas turbine/HRSG power train. The derivation of the emission factors is detailed in Appendix A.

Table B-7
Worst-Case Annual TAC Emissions for Gas Turbines and HRSGs

Toxic Air Contaminant	Emission Factor[a] (lb/MM scf)	lb/yr-power train[b]	g/sec
Acetaldehyde[c]	1.37E-01	1,884.2	2.71E-02
Acrolein	1.89E-02	260	3.74E-03
Ammonia[d]	6.75	92,834.1	1.34
Benzene[c]	1.33E-02	183	2.63E-03
1,3-Butadiene[c]	1.27E-04	1.75	2.51E-05
Ethylbenzene	1.79E-02	246	3.54E-03
Formaldehyde[c]	9.17E-01	4,414.1[e]	6.35E-02
Hexane	2.59E-01	3,562	5.12E-02
Naphthalene	1.66E-03	22.8	3.28E-04
Propylene	7.71E-01	10,603.7	1.53E-01
Propylene Oxide[c]	4.78E-02	657.4	9.45E-03
Toluene	7.10E-02	976.5	1.40E-02
Xylenes	2.61E-02	359	5.16E-03
Total PAHs	1.06E-04	1.46	2.10E-05

[a]CARB CATEF II Database emission factors, mean values

[b]from each gas turbine/HRSG power train (S-1 & S-2, S-3 & S-4, S-5 & S-6, and S-7 & S-8); based upon annual gas usage rate of 13,753.2 MM scf/yr-turbine/HRSG

[c]carcinogenic compounds

[d]based upon the worst-case ammonia slip from the SCR system of 5 ppmvd @ 15% O_2

[e]reflects oxidation catalyst abatement efficiency of 65% (wt) for formaldehyde

The projected toxic air contaminant emissions from each exempt 11-cell cooling tower are summarized in **Table B-8**. The emissions are based upon an water circulation rate of 148,111 gpm and 8,760 hours of operation per year.

Table B-8 Worst-Case TAC Emissions for Each 11-Cell Cooling Tower

Toxic Air Contaminant	Emission Factor (lb/hr)	Annual Emission Rate (lb/yr)	Annual Emission Rate (lb/yr-cell)	Risk Screening Trigger Level (lb/yr)
Arsenic	1.48E-05	0.13	1.18E-02	0.025
Bromide	1.56E-03	1.4	1.27E-01	330
Cadmium	2.96E-05	0.26	2.36E-02	0.046
Trivalent chromium	1.85E-05	0.16	1.45E-02	None specified
Copper	3.70E-05	0.32	2.91E-02	460
Fluoride	6.67E-04	5.84	0.53	None specified
Mercury	5.93E-06	0.052	4.73E-03	58
Nickel	1.48E-05	0.13	1.18E-02	0.73
Manganese	5.19E-05	0.45	4.09E-02	77
Sulfate	3.19E-01	2,790	254	None specified
Zinc	6.66E-05	0.58	5.27E-02	6,800

B-6.0 Maximum Facility Emissions

The maximum annual facility regulated air pollutant emissions for the proposed gas turbines and HRSGs are shown in **Table B-9**. The total permitted emission rates shown below are the basis of permit condition limits and emission offset requirements, if applicable.

Table B-9 Maximum Annual Facility Regulated Air Pollutant Emissions (ton/yr)

Source	NO_2	CO	POC	PM_{10}	SO_2	H_2SO_4
S-1 CTG and S-2 HRSG[a]	62.659	86.071	15.912	46.998	7.297	8.453
S-3 CTG and S-4 HRSG[a]	62.659	86.071	15.912	46.998	7.297	8.453
S-5 CTG and S-6 HRSG[a]	62.659	86.071	15.912	46.998	7.297	8.453
S-7 CTG and S-8 HRSG[a]	62.659	86.071	15.912	46.998	7.297	8.453
Sub-Total	**250.636**	**344.284**	**63.646**	**187.993**	**29.186**	**33.810**
11-Cell Cooling Towers	0	0	0	6.132	0	0
S-9 Diesel Fire Pump Engine	0.073	0.029	0.016	0.002	0.010	0
Total Facility Emissions	**250.709**	**344.313**	**63.662**	**194.127**	**29.196**	**33.810**

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

Table B-10
Baseload Air Pollutant Emission Rates for Gas Turbines and HRSGs
(Excluding Gas Turbine Start-up and Shutdown Emissions)

	NO_2	CO	POC	PM_{10}	SO_2
Each Gas Turbine (1875.5 MM BTU/hr @17°F)					
lb/hr-source	13.71	16.5	2.36	9	1.75
lb/day-source	329	396	56.6	216	42
Each Gas Turbine/HRSG Power Train (2,147.7 MM BTU/hr @ 17°F and 24 hour per day duct burner firing					
lb/hr-power train	15.67	18.9	4.42	12.75	2
lb/day-power train	376	453.6	106.1	306	48

The maximum daily regulated air pollutant emissions per source including gas turbine start-up emissions are shown in **Table B-11**.

Table B-11 Maximum Daily Regulated Air Pollutant Emissions per Power Train (lb/day)

Source (operating mode)	NO_2	CO	POC	PM_{10}	SO_2
Gas Turbine (start-up)	415.5	1,180.2	92.8	63.75	10
Gas Turbine & HRSG (full load w/duct burner firing @ 17°F)	297.7	400.7	79	242.25	38
Total	**713.2[a]**	**1,580.9[b]**	**171.8[b]**	**306[a]**	**48[a]**

[a]worst-case daily NO_2, PM_{10}, and SO_2 emissions occur during a 5-hour cold start followed by 19 hours of full load operation with duct burner firing @17°F

[b]worst-case daily CO and POC emissions occur during a 3-hour warm start followed by 21 hours of full load operation with duct burner firing @17°F

Table B-12 summarizes the worst-case daily regulated air pollutant emissions from permitted sources. These are the basis of permit condition daily mass emission limits. The operating scenario assumes simultaneous cold start-up of two gas turbines followed by 19 hours of full load operation with duct burner firing. The other two gas turbines start-up after a one hour delay to insure that the PSD impact modeling analysis for 1-hr standards is preserved. Fire pump diesel engine operates for a maximum of 0.5 hours per day for exercising.

Table B-12 Worst-Case Daily Regulated Air Pollutant Facility Emissions from Permitted Sources (lb/day)

Source (Operating Mode)	NO_2	CO	POC	PM_{10}	SO_2
Two Gas Turbines (start-up)	831[a]	2360.5[b]	158[b]	127.5	20
Two Gas Turbine/HRSG Power Trains (full load w/Duct Burner Firing @ 17°F)	595.5	800.1	185.6	484.5	76
Two Gas Turbines (start-up)	831[a]	2360.5[b]	158[b]	127.5	20
Two Gas Turbine/HRSG Power Trains (full load w/Duct Burner Firing @ 17°F)	564.1	762	176.8	459	72
Gas Turbine/HRSG Powertrain Sub-total	**2,821.6**	**6,283**	**678.4**	**1,198.5 (1,224)[c]**	**188 (192)[c]**
S-9 Diesel Fire Pump Engine	2.8	1.1	0.6	0.07	0.38
Total	**2,824.4**	**6,284.1**	**679**	**1,224.07**	**192.4**

[a]worst-case daily facility NO_2 emissons occur during a 5-hour cold start followed by full load operation with duct burner firing at 17°F for the remainder of the day

[b]worst-case daily facility CO and POC emissons occur during a 3-hour warm start followed by full load operation with duct burner firing at 17°F for the remainder of the day

[c]daily maximum emissions for PM_{10} and SO_2 occur when all four turbines are operating at full load w/duct burner firing @ 17°F for 24 hours

B-7.0 Modeling Emission Rates

Tables B-13 through B-19 show the emission rates that were used to model the air quality impacts of the TPP to determine compliance with applicable State and Federal ambient air quality standards for the pollutants indicated. A screening impact analysis of gas turbine/HRSG duct burner emission rates and stack gas characteristics showed that the worst-case annual average impacts occur under the equipment operating scenarios shown in each table.

Table B-13
NO_2 Emission Rates for Worst-Case Annual-Average Impacts

Source (Operating Mode)	NO_2		
	lb/yr	lb/hr	g/s
Gas Turbine (27 hot start-ups/turbine)	3,137.4		
Gas Turbine (9 warm start-ups/turbine)	2,032.3		
Gas Turbine (12 cold start-ups/turbine)	4,986		
Gas Turbine (2,800 firing hours/turbine @ 1,756.7 MM BTU/hr)	35,952		
Gas Turbine and associated HRSG (5,260 hours/turbine w/duct burner firing @ 2,018.9 MM BTU/hr)	77,637.6		
Total Emissions for each Gas Turbine/HRSG Pair	123,745.3	14.126	1.78
S-9 Fire Pump Diesel Engine (50 firing hours/year)	370.5	0.042	5.29E-03

Table B-14
PM_{10} Emission Rates for Worst-Case Annual-Average Impacts

Source (Operating Mode)	PM_{10}		
	lb/yr	lb/hr	g/s
Gas Turbine (27 hot start-ups)	515.7		
Gas Turbine (9 warm start-ups)	344.25		
Gas Turbine (12 cold start-ups)	765		
Gas Turbine (2,800 hours/turbine @ 1,756.7 MM BTU/hr)	25,200		
Gas Turbine & HRSG (5,260 hours w/duct burner firing @ 2,018.9 MM BTU/hr)	67,065		
Total Emissions for each Gas Turbine/HRSG Pair	93,890	10.72	1.35
11-Cell Cooling Towers (2)	12,264	1.4	0.008[a]
S-9 Fire Pump Diesel Engine (50 firing hours/year)	6.5	7.42E-04	9.34E-05

[a]emission rate per cell (22 total for both cooling towers)

Table B-15
PM_{10} Emission Rates for Worst-Case 24-hour Average Impacts (February through October)

Source (Operating Mode)	PM_{10}		
	lb/day	lb/hr	g/s
S-1, S-3, S-5, & S-7 Gas Turbines (24 hour operation with duct burner firing @ 2,147.7 MM BTU/hr; 17oF)	306	12.75	1.61
11-Cell Cooling Towers (2)	33.6	1.4	0.008[a]
S-9 Fire Pump Diesel Engine[b]	0.065	0.0027	3.41E-04

[a]emission rate per cell (22 total)

[b]based upon 0.5 hour of full-load operation per 24-hour period

Table B-16
PM_{10} Emission Rates for Worst-Case 24-hour Average Impacts (November through January)

Source (Operating Mode)	PM_{10}		
	lb/day	lb/hr	g/s
S-1, S-3, S-5, & S-7 Gas Turbines (Daily maximum restricted by permit conditon for November through January)	270	11.25	1.417
11-Cell Cooling Towers (2)	33.6	1.4	0.008[a]
S-9 Fire Pump Diesel Engine[b]	0.065	0.0027	3.41E-04

[a]emission rate per cell (22 total)
[b]based upon 0.5 hour of full-load operation per 24-hour period

Table B-17
CO Emission Rates for Worst-Case 8-hour Average Impacts

Source (Operating Mode)	CO		
	lb	lb/hr	g/s
Each Gas Turbine (3-hour warm start-up)	1,180.25		
Each Gas Turbine & HRSG (5 hour operation w/duct burner firing @ 2,147.7 MM BTU/hr; 17°F)	94.5		
Total:	1,274.75	159.34	20.07[b]
S-9 Fire Pump Diesel Engine	0.875[a]	0.109	0.0138

[a]assuming 0.5 hour exercising per day at emission rate of 1.75 lb/hr
[b]applicant calculated and modeled a slightly higher emission rate of 20.840 g/s

Table B-18
NO_2 and CO Emission Rates for Worst-Case 1-hour Average Impacts

Source (Operating Mode)	NO_2 lb/hr	NO_2 g/s	CO lb/hr	CO g/s
One Gas Turbine & HRSG (start-up mode)	150 (cold start-up)	18.90	663 (warm start-up)	83.528
One Gas Turbine & HRSG (100% Load w/Duct Burner Firing @ 17oF; 2,147.7 MM BTU/hr)	15.67	1.974	18.9	2.38
S-9 Fire Pump Diesel Engine	3.705[a]	0.467	0.875[a]	0.109

[a]maximum 0.5 hour exercising per day

B-8.0 Maximum Facility Emissions During Commissioning Period

Table B-19 summarizes the worst-case 1-hour and 8-hour emission rates for the TPP during the commissioning period, when the SCR systems and oxidation catalysts are not yet installed and operational. These emission rates were used as inputs in air quality impact models that were used to determine if the TPP would contribute to an exceedance of the 1-hour State NO_2 ambient air quality standard, the 1-hour State and Federal CO standards, and the 8-hour State and Federal CO standards during the commissioning of the gas turbines, HRSGs, and related equipment. It is assumed that only one gas turbine will be commissioned at one time.

Table B-19
Worst-Case Short-Term NO_2 and CO Emission Rates for Gas Turbines during Commissioning Period

	NO_2		CO	
1-hour Emission Rates	lb/hr	g/s	lb/hr	g/s
Each Gas Turbine	155.5[a]	19.593	95.4[b]	12.02
8-hour Emission Rates[c]				
Each CTG & HRSG Pair	n/a	n/a	165.4	20.84

[a]based upon a conservative exhaust gas NO_x emission concentration of 36 ppmvd @ 15% O_2 for each turbine when operating without abatement by the SCR system; fuel use rate assumed to be approximately 50% of full load, or 844 MM BTU/hr, calculated as follows:

NO_2 = (36 ppmv/2 ppmv)(0.00731 lb NO_2/MM BTU)(844 MM BTU/hr) = 111 lb/hr

[b]based upon turbine exhaust gas CO emission concentration of 20 ppmvd @ 15% O_2 at fuel use rate of 2,147.7 MM BTU/hr, calculated as follows:

CO = (20 ppmv/4 ppmv)(0.0088 lb CO/MM BTU)(2,147.7 MM BTU/hr) = 94.5 lb/hr

[c]based upon one 3-hour warm start-up, followed by 5 hours of 100% load operation of CTG and HRSG at the maximum combined heat input rate of 2,147.7 MM BTU/hr; see Table B-19 for further detail

Appendix C

Emission Offsets

Table C-1 Emission Offset Summary

	NO_x	CO	POC	PM_{10}	SO_2
BAAQMD Calculated New Source Emission Increases[a] (ton/yr)	250.709	344.313	63.662	187.995[b]	29.196
Proposed New Source Annual Emission Limits[c] (ton/yr)	249.850	335.660	60.435	189.95[b]	29.55
Offset Requirement Triggered	Yes	n/a	Yes	Yes	No
Offset Ratio	1.15:1.0[d]	n/a	1.15:1.0[d]	1.0:1.0[e]	n/a
Offsets Required (tons)	**287.328**	**0**	**69.500**	**189.950**	**0**
ERCs identified by Applicant (tons)	**251.396**	**0**	**105.447**	**226.800**	**0**
Outstanding Offset Balance (tons)	**-35.932[f]**	**0**	**+37.947[f]**	**+36.850**	**0**

[a]sum of Gas Turbine (S-1, S-3, S-5, and S-7), HRSG (S-2, S-4, S-6, and S-8) and S-9 Fire Pump Diesel Engine emission increases

[b]does not include emissions from exempt cooling towers

[c]per applicant's emission estimates

[d]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 and POC emissions from permitted sources will each exceed 50 tons per year

[e]pursuant to District Regulation 2-2-303

[f]pursuant to District Regulation 2-2-302.2, the applicant has opted to provide POC emission offsets to offset the outstanding NOx emission increases at a ratio of 1:1

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 and other compounds) in the cooling tower water, the proposed Tesla Power Plant 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 Toxic 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 Toxic 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 70-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.

In anticipation of pending amendments to District Regulation 2, Rule 1 and Rule 2, a health risk screening was performed to determine the impact of diesel exhaust particulate from the standby fire pump diesel engine. Because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the total combined carcinogenic risk for the facility does not exceed 1 in one million. As shown in Table D-1, the increased carcinogenic risk was found to be less than one in one million and is therefore considered to be not significant.

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)	Chronic Hazard Index	Acute Hazard Index[a]
Gas Turbines and HRSGs	0.14	0.013	0.467
Fire Pump Diesel Engine	0.8	0.001	--
Exempt Cooling Towers	0.14	0.01	0.039
Maximum Facility Risk:	0.81[b]	0.017	0.472

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

[b]because the location of maximum impact for the diesel engine does not coincide with the locations of maximum impact for the other sources, the carcinogenic risk numbers do not add directly to determine the maximum facility cancer risk shown

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 of 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 proposed Tesla Power Project is deemed to be in compliance with the BAAQMD Toxic Risk Management Policy.

Appendix E

SUMMARY OF AIR QUALITY IMPACT ANALYSIS FOR THE TESLA POWER PLANT

May 14, 2002

BACKGROUND

The Tesla Power Plant, LLC has submitted a permit application (#3506) for a proposed 1120-MW combined cycle power plant. The facility is to be composed of four natural gas-fired turbines with heat recovery steam generators, supplemental burners (duct burners), a 22-cell cooling tower, and a diesel fire water pump engine. 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 (tons/year)	Significant emission rate?
NO_x (as NO_2)	249.85	100	40	yes
CO	484.13	100	100	yes
PM_{10}	196.05	100	15	yes
SO_2	29.55	100	40	no

Table I shows the proposed project emissions and the pollutant significant emission levels for nitrogen oxides (NO_x), carbon monoxide (CO), respirable particulate matter (PM_{10}) and sulfur dioxide (SO_2). The table shows that the NO_2, CO and PM_{10} ambient impacts from the project all exceed the significance level and must be modeled. The detailed requirements for an air quality impact analysis for these pollutants are given in Sections 304, 305 and 306 of the District's NSR Rule and 40 CFR 51.166 of the Code of Federal Regulations.

The District's NSR Rule also contains requirements for certain additional impact analyses associated with air pollutant emissions. An applicant for a permit that requires an air quality impact analysis must also, according to Section 417 of the NSR Rule, provide an analysis of the impact of the source and source-related growth on visibility, soils and vegetation.

AIR QUALITY IMPACT ANALYSIS SUMMARY

The required contents of an air quality impact analysis are specified in Section 414 of Regulation 2 Rule 2. According to subsection 414.1, if the maximum air quality impacts of a new or modified stationary source do not exceed significance levels for air quality impacts, as defined in Section 2-2-233, no further analysis is required. (Consistent with EPA regulations, it is assumed that emission increases will not interfere with the attainment or maintenance of AAQS, or cause an exceedance of a PSD increment if the resulting maximum air quality impacts are less than specified significance levels). If the maximum impact for a particular pollutant is predicted to exceed the significance impact level, a full impact analysis is required involving estimation of background pollutant concentrations and, if applicable, a PSD increment consumption analysis. EPA also requires a Class I increment analysis of any PSD source which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) in a Class I area.

Air Quality Modeling Methodology

Maximum ambient concentrations of NO_2, CO and PM_{10} were estimated for various plume dispersion scenarios using established modeling procedures. The plume dispersion scenarios addressed include simple terrain impacts (for receptors located below stack height), complex terrain impacts (for receptors located at or above stack height), impacts due to building downwash, and impacts due to inversion breakup fumigation.

Emissions from the turbines will be exhausted from four 200 foot exhaust stacks. Emissions from a 22-cell cooling tower will be released at a height of 55.5 feet. Table II contains the emission rates used in each of the modeling scenarios: turbine commissioning, maximum 1-hour, maximum 8-hour, maximum 24-hour, and maximum annual average. Commissioning is the original startup of the turbines and only occurs during the initial operation of the equipment after installation. The maximum 1-hour takes into account the startup of two turbines, with the other two turbines at maximum load. Different sets of Maximum 24-hour PM_{10} emissions for the turbine/duct burners exist for the periods of February – October and November – January. The applicant proposed, and will be limited by a permit condition to, lower 24-hour average PM_{10} emissions for the winter months of November through January.

The EPA models SCREEN3 and ISCST3 were used in the air quality impacts analysis. A land use analysis showed that the rural dispersion coefficients were required for the analysis. The models were run using three years of meteorological data (1997 through 1999) collected approximately 3.5 km east of the project at the San Joaquin Valley Unified Air Pollution Control District's Tracy Monitoring Station. The Ozone Limiting Method was employed to convert one-hour NO_x impacts into one-hour NO_2 impacts. Hourly ozone monitoring data was also available from the Tracy Monitoring site for the same period (1997-1999). Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. 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. Because complex terrain was located nearby, complex terrain impacts were considered. Inversion breakup fumigation was evaluated using the SCREEN3 model.

TABLE E-2
Averaging Period Emission Rates used in Modeling Analysis (g/s)

Pollutant Source	Max.[1] (1-hour)	Commissioning[2] (1-hour)	Max. (8-hour)	Max. Feb - Oct (24-hour)	Max. Nov - Jan (24-hour)	Max. Annual Average
NO_x						
Turbine/Duct Burner 1	18.90	19.593	—	—	—	1.797
Turbine/Duct Burner 2	18.90	19.593				1.797
Turbine/Duct Burner 3	1.974	19.593				1.797
Turbine/Duct Burner 4	1.974	19.593				1.797
Fire Water Pump	0.467	—				2.77×10^{-3}
Each Cooling Tower Cell (22 total)	—	—				—
CO						
Turbine/Duct Burner 1	83.538	12.020	20.840	—	—	—
Turbine/Duct Burner 2	83.538	12.020	20.840			
Turbine/Duct Burner 3	3.606	12.020	20.840			
Turbine/Duct Burner 4	3.606	12.020	20.840			
Fire Water Pump	0.110	—	0.0138			
Each Cooling Tower Cell (22 total)	—	—	—			
PM_{10}						
Turbine/Duct Burner 1	—	—	—	1.593	1.417	1.366
Turbine/Duct Burner 2				1.593	1.417	1.366
Turbine/Duct Burner 3				1.593	1.417	1.366
Turbine/Duct Burner 4				1.593	1.417	1.366
Fire Water Pump				3.41×10^{-4}	3.41×10^{-4}	4.86×10^{-5}
Each Cooling Tower Cell (22 total)				7.98×10^{-3}	7.98×10^{-3}	7.98×10^{-3}

[1]Max 1-hour has two turbines in start-up, while the other two turbines are at maximum load. Start-up is the beginning of any of the subsequent duty cycles to bring a turbine from idle status up to power production. [2]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 III for the averaging periods for which AAQS and PSD increments have been set. Shown in Figure 1 are the locations of the maximum modeled impacts.

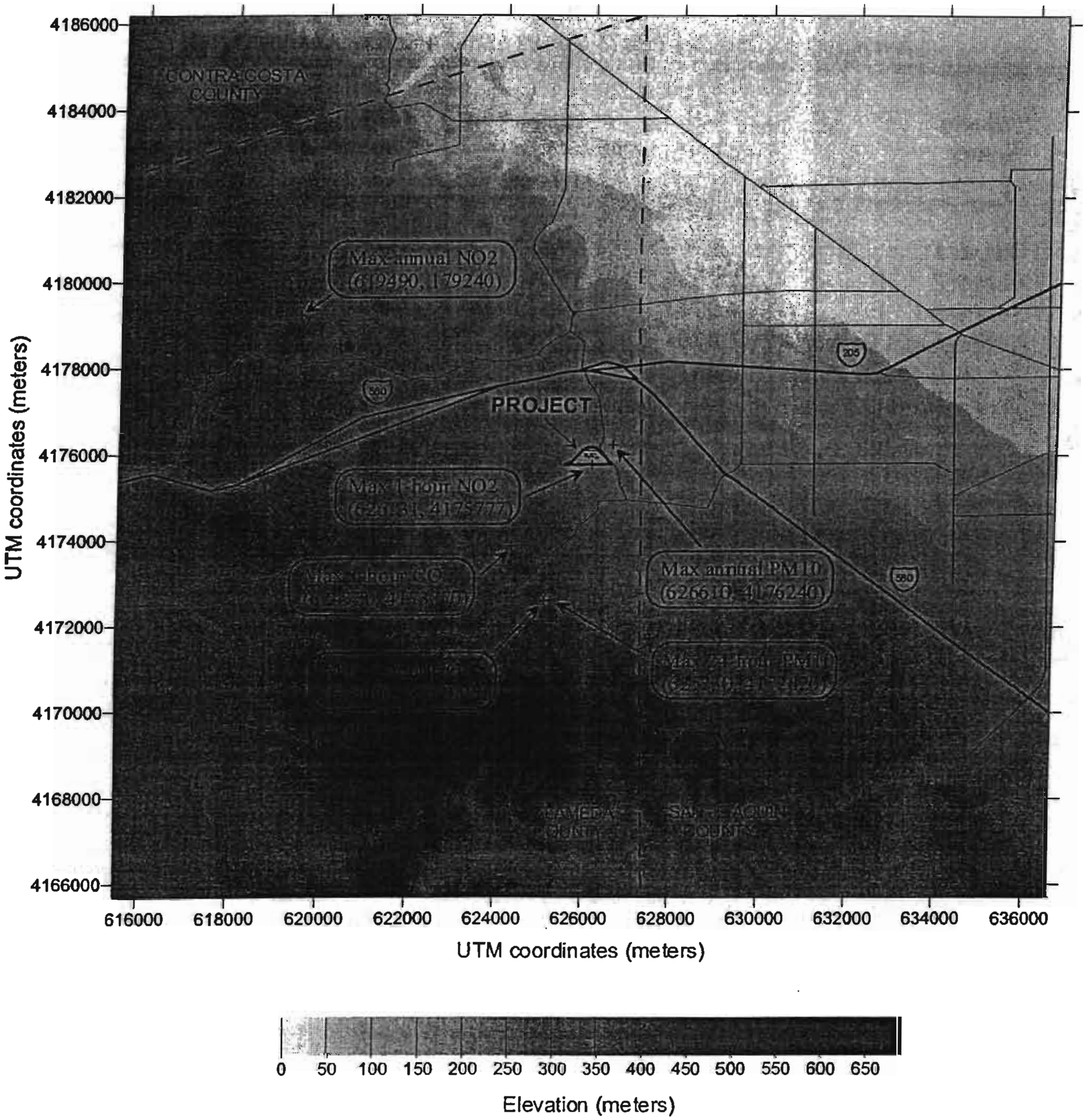

Figure 1. Location of project maximum impacts.

Also shown in Table III 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 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 impact.

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	Inversion Break-up Fumigation Impact	ISCST3 Modeled Impact	Significant Air Quality Impact Level
NO_2	1-hour	165.8	66.2	**187.6**	19
	annual	—	—	**0.23**	1.0
CO	1-hour	375.5	268.9	**1366.8**	2000
	8-hour	—	—	**230.24**	500
PM_{10}	24-hour	—	3.20	**4.97**	5
	annual	—	—	**0.46**	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, the modeled NO_2 impact is well 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	0.23

The California Air Resources Board-operated Stockton-Hazelton Monitoring Station, located 36.6 km northeast of the project, was chosen as being conservatively representative of the regional background NO_2 concentrations. Table E-5 contains the concentrations measured at the station over the three modeling years (1997 through 1999).

TABLE E-5
Background NO_2 ($\mu g/m^3$) at the Stockton-Hazelton Monitoring Station for the Modeling Years 1997 - 1999 (maximum is in bold type)

Year	NO_2 Highest 1-hour average
1997	169
1998	192
1999	**199**

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.

TABLE E-6
California and National Ambient Air Quality Standards and Ambient Air Quality Levels from the Proposed Project ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Background	Maximum project impact	Maximum project impact plus maximum background	California Standard	National Standard
NO_2	1-hour	199	187.6	387	470	---

CLASS I PSD INCREMENT ANALYSIS

EPA requires an increment analysis of any PSD source which increases NO_2 or PM_{10} concentrations by 1 $\mu g/m^3$ or more (24-hour average) inside a Class I area. Point Reyes National Seashore is located roughly 103 km to the west of the project and Pinnacles National Monument is located roughly 136 km south southeast of the project. Table E-7 shows the results of an impact analysis using ISCST3 for the maximum 24-hour NO_2 and PM_{10} impacts within the Class I areas. All impacts were below the 1 $\mu g/m^3$ increments trigger level.

TABLE E-7
Maximum Predicted Ambient Impacts of Proposed Project ($\mu g/m^3$)

Pollutant	Averaging Time	Point Reyes National Seashore	Pinnacles National Monument
NO_2	24-hour	0.62	0.38
PM_{10}	24-hour	0.24	0.14

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 the Point Reyes National Seashore or at the Pinnacles National Monument.

The project maximum one-hour average NO_2, including background, is 387 $\mu g/m^3$. 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 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 and PM_{10}. The 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 Analysis Data

ONSITE SYCOM
Energy Corporation

Cost Analysis of NO_x Control Alternatives for Stationary Gas Turbines

Contract No. DE-FC02-97CHIO877

Prepared for:

U.S. Department of Energy
Environmental Programs
Chicago Operations Office
9800 South Cass Avenue
Chicago, IL 60439

Prepared by:

ONSITE SYCOM Energy Corporation
701 Palomar Airport Road,
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Carlsbad, California 92009

October 15, 1999

TABLE A-5
1999 CONVENTIONAL SCR 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	161 MW
Direct Capital Costs (DC):		Source			
Purchased Equip. Cost (PE):		MHIA			
Basic Equipment (A):		MHIA	$240,000	$660,000	$2,100,000
Ammonia injection skid and storage	0.00 x A	MHIA	included	included	included
Instrumentation	0.00 x A	OAQPS	included	included	included
Taxes and freight:	0.08 A x B	OAQPS	$19,015	$52,746	$169,530
PE Total:			$256,704	$712,066	$2,288,649
Direct Installation Costs (DI):*					
Foundation & supports:	0.08 x PE	OAQPS	$20,536	$56,965	$183,092
Handling and erection:	0.14 x PE	OAQPS	$35,939	$99,689	$320,411
Electrical:	0.04 x PE	OAQPS	$10,268	$28,483	$91,546
Piping:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Insulation:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Painting:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
DI Total:			$77,011	$213,620	$686,595
DC Total:			$333,716	$925,686	$2,975,244
Indirect Costs (IC):					
Engineering:	0.10 x PE	OAQPS	$25,670	$71,207	$100,000
Construction and field expenses:	0.05 x PE	OAQPS	$12,835	$35,603	$114,432
Contractor fees:	0.10 x PE	OAQPS	$25,670	$71,207	$228,865
Start-up:	0.02 x PE	OAQPS	$5,134	$14,241	$45,773
Performance testing:	0.01 x PE	OAQPS	$2,567	$7,121	$22,886
Contingencies:	0.03 x PE	OAQPS	$7,701	$21,362	$68,659
IC Total:			$79,578	$220,741	$580,616
Total Capital Investment (TCI = DC + IC):			$413,294	$1,146,427	$3,555,861
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	$13,125
Utility Costs:	0% thermal eff 600 (F) operating temp				
Gas usage	0.0 (MMcf/yr) 1,000 (Btu/ft3) heat value				
Gas cost	3,000 ($/MMcf)	variable			
Perf. loss:	0.5%				
Electricity cost	0.06 ($/kwh) performance loss cost penalty	variable	$10,584	$57,960	$405,720
Catalyst replace:	assume 30 ft^3 catalyst per MW, $400/ft^3, 7 yr. life	MHIA	$10,352	$56,690	$396,833
Catalyst dispose:	$15/ft^3*30 ft^3/MW*MW*.2054 (7 yr amortized)	OAQPS	$388	$2,126	$14,881
Ammonia:	360 ($/ton) [tons NH_3 = tons NO_x * (17/46)]	variable	$3,510	$14,820	$108,257
NH_3 inject skid:	5 (kW) blower 5 kw (NH_3/H_2O pump)	MHIA	$5,040	$7,560	$27,720
Total DAC:			$71,219	$180,500	$994,755
Indirect Annual Costs (IAC):					
Overhead:	60% of O&M	OAQPS	$24,806	$24,806	$24,806
Administrative:	0.02 x TCI	OAQPS	$8,266	$22,929	$71,117
Insurance:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Property tax:	0.01 x TCI	OAQPS	$4,133	$11,464	$35,559
Capital recovery:	10% interest rate, 15 yrs - period; 0.13 x TCI	OAQPS	$52,976	$143,272	$415,329
Total IAC:			$94,314	$213,935	$582,370
Total Annual Cost (DAC + IAC):			$165,533	$394,435	$1,577,125
NO_x Emission Rate (tons/yr) at 42 ppm:			33.4	141.0	1030.0
NO_x Removed (tons/yr) at 9 ppm,	79% removal efficiency		26.4	111.4	813.7
Cost Effectiveness ($/ton):			$6,274	$3,541	$1,938
Electricity Cost Impact (¢/kwh):			0.469	0.204	0.117

*Assume modular SCR is inserted into existing HRSG spool piece

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

REVISED BEST AVAILABLE CONTROL TECHNOLOGY ANALYSIS

TOWANTIC ENERGY PROJECT

FEBRUARY 2000

R·W·BECK

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 equipmen 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.

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[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

Appendix G

Compliance Certification

Midway Power, LLC
700 Universe Boulevard, Juno Beach, Florida 33408
Phone: (561) 691-7099 Facsimile: (561) 691-7307

Certification

I, Derrel Grant, on behalf of FPL Energy, LLC dba Midway Power, LLC, hereby certify under penalty of perjury as follows:

1. I am authorized to make this certification on behalf of Midway Power.

2. This certification is made pursuant to Section 2-2-307 of the Rules and Regulations of the Bay Area Air Quality Management District (BAAQMD).

3. To the best of the undersigned's knowledge, all major stationary sources owned or operated by FPL Energy in the State of California are either in compliance or on a schedule of compliance with all applicable state and federal emission limitations and standards.

Each of these statements herein is made in good faith. Accordingly, it is FPL Energy's understanding in submitting this certification that the BAAQMD shall take no action against FPL Energy or any of its employees based on any statement made in this certification.

Derrel Grant
Vice President
Midway Power, LLC

Dated: 12/09/02

STATE OF CALIFORNIA

State Energy Resources
Conservation and Development Commission

In the Matter of:	**Docket No. 01-AFC-21**
Application for Certification for the Tesla Power Project By Midway Power LLC	PROOF OF SERVICE

I, Carole Phelps, declare that on March 4, 2003, I deposited copies of the attached **Final Determination of Compliance for the Tesla Power Project** with first class postage thereon fully prepaid and addressed to the following:

DOCKET UNIT
I have sent the original signed document plus the required 12 copies to the address below:

CALIFORNIA ENERGY COMMISSION
DOCKET UNIT, MS-4
ATTN: Docket No. 01-AFC-21
1516 Ninth Street
Sacramento, CA 95814-5512

****
I have also sent individual copies to:

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

Carole Phelps

Carole Phelps