Petition to Amend Air Quality Conditions in the Gateway Generating Station Project Final Decision

Submitted to the

California Energy Commission

January 15, 2008

Submitted by

Pacific Gas and Electric Company

With Technical Assistance By

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Table of Contents

TABLE OF CONTENTS I

1.0 INTRODUCTION 1

1.1 BACKGROUND 1
1.2 DESCRIPTION OF PROPOSED AMENDMENT 2
1.3 NECESSITY OF PROPOSED CHANGES 2
1.4 SUMMARY OF ENVIRONMENTAL IMPACTS 2
1.5 CONSISTENCY OF CHANGES WITH LICENSE 3

2.0 DESCRIPTION OF PROJECT CHANGES 4

2.1 PROPOSED PROJECT CHANGES 4
2.1.1 Revise Emission Limits 5
2.1.2 Changes to the Equipment Description for Auxiliary Units 6
2.2 NECESSITY OF PROPOSED CHANGE 6

3.0 ENVIRONMENTAL ANALYSIS OF THE PROJECT CHANGES 7

3.1 AIR QUALITY 7
3.2 PUBLIC HEALTH 7
3.3 CUMULATIVE IMPACTS 8
3.3.1 Cumulative Air Quality Impacts 8
3.4 LORS 8

4.0 PROPOSED MODIFICATIONS TO THE CONDITIONS OF CERTIFICATION 9

5.0 POTENTIAL EFFECTS ON THE PUBLIC 10

6.0 LIST OF PROPERTY OWNERS 11

7.0 POTENTIAL EFFECTS ON PROPERTY OWNERS 12

ATTACHMENTS

Attachment A: Application to the BAAQMD for Modifications to the Authority to Construct (Air Quality Analysis and Screening Health Risk Assessment)

Attachment B: Proposed Changes to the Commission Decision Air Quality Conditions of Certification

Attachment C: List of Property Owners

1.0 Introduction

Since acquiring the original Contra Costa Unit #8 project in late 2006 and renaming it the Gateway Generating Station Project (GGS), Pacific Gas and Electric Company (PG&E) has submitted several petitions to the California Energy Commission (CEC) requesting approval of modifications to the project description and CEC Conditions of Certification as set forth in the original Final Decision dated May 30, 2001. These changes have been both major (e.g., changing the plant design from a wet cooled system to a dry cooled system) and minor (adding two new water storage tanks), but all have been necessary to allow PG&E to design, build, and ultimately operate the GGS project as efficiently and reliably as possible.

As discussed below, PG&E is submitting this new Petition to Amend the GGS Final Decision to address several air quality related issues for the project.

1.1 Background

The Gateway Generating Station Project is a nominal 530 MW combined cycle power plant located at 3225 Wilbur Avenue in the City of Antioch. The project, originally developed by Mirant Delta LLC as Contra Costa Power Plant Unit #8 (CC8), was certified by the California Energy Commission on May 30, 2001. Construction began in late 2001 but was suspended by Mirant in February 2002. In late 2006, Pacific Gas and Electric Company (PG&E) acquired the project through an Asset Transfer Agreement and renamed it the Gateway Generating Station (GGS). The CEC Compliance Project Manager issued a letter on January 19, 2007 authorizing PG&E to restart construction of the project.

In December 2006, PG&E submitted a Petition to Amend with the CEC requesting approval of several proposed changes to the project design, including redesign of the cooling system to eliminate wet cooling and eliminating the use of steam power augmentation. This amendment was approved by the CEC on August 1, 2007. Because of the need to get the cooling system-related project changes approved quickly, the December 2006 Petition to Amend did not include any project modifications that required changes to the Authority to Construct (ATC) issued by the Bay Area Air Quality Management District (BAAQMD or District) for the project. However, when PG&E took over the CC8 project, a meeting was held with the District staff to discuss PG&E's plans for the project. At that time, the District staff was made aware that (1) a Petition to Amend the CEC Final Decision, which did not include air quality permit-related changes, had been filed with the CEC in December 2006, and (2) a subsequent permit application would be filed in mid- to late 2007 that would address proposed changes to the ATC conditions and to the CEC's air quality-related conditions of certification. The referenced permit application was submitted to the BAAQMD on December 18, 2007, and this document constitutes PG&E's related request to the CEC to amend certain air quality conditions of certification in the GGS Final Decision.

This Petition to Amend the GGS Project Final Decision contains the information required pursuant to Section 1769 (Post Certification Amendments and Changes) of the CEC Siting Regulations. The revisions are summarized in Section 1.2.

1.2 Description of Proposed Amendment

After careful evaluation and a comprehensive review of the project design, both as originally proposed by Mirant for the CC8 project and modified by PG&E in its dry cooling amendment, PG&E has determined that several changes to the project description are necessary. The major changes are summarized below; more detail on all of the specific project changes is provided in Section 2.1 of this Amendment.

- Replace the permitted natural gas-fired preheater with a smaller dewpoint heater and increase allowable daily hours of operation.
- Change the allowable emission rates for the gas turbines during startup operations.
- Reduce the permitted hourly emission rates for NOx, CO, and PM_{10}, based on current BACT and on operating experience from other 7FA gas turbine facilities.
- Increase the daily and annual emission rates for CO, based on operating experience from other 7FA gas turbine facilities.
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience.
- Add a 300 hp Diesel fire pump at the facility.

1.3 Necessity of Proposed Changes

Sections 1769 (a) (1) (A), (B), and (C) of the CEC Siting Regulations require a discussion of the necessity for the proposed revisions to the GGS project and whether the revisions are based on information known by the petitioner during the certification proceeding. The necessity for each revision is addressed in Section 2. These changes are necessary to reflect new design information and/or standards that were made after ownership of the project was transferred to PG&E in late 2006.

1.4 Summary of Environmental Impacts

Section 1769 (a) (1) (E) of the CEC Siting Regulations requires that an analysis be conducted to address impacts the proposed revisions may have on the environment and proposed measures to mitigate significant adverse impacts. Section 1769 (a) (1) (F) requires a discussion of the impacts of proposed revisions on the facility's ability to comply with applicable laws, ordinances, regulations, and standards (LORS). Section 3.0 discusses the potential impacts of the proposed changes on the environment, as well as the proposed revisions' consistency with LORS.

1.5 Consistency of Changes with License

Section 1769 (a) (1) (D) of the CEC Siting Regulations requires a discussion of the consistency of each proposed project revision with the assumptions, rationale, findings, or other bases of the final decision and whether the revision is based on new information that changes or undermines the bases of the final decision. Also required is an explanation of why the changes should be permitted. None of the proposed revisions undermines the assumptions, rationale, findings, or other basis of the Commission Decision for the project. The revisions consist of beneficial changes to the project that increase reliability and reduce environmental impacts.

The remainder of this Petition to Amend the GGS Final Decision presents a detailed project description (Section 2), environmental analysis of the proposed project changes (Section 3), proposed modifications to the Conditions of Certification (Section 4), potential effects on the public (Section 5), a list of property owners potentially impacted by the proposed changes (Section 6), and potential effects on the property owners (Section 7).

2.0 Description of Project Changes

Consistent with the California Energy Commission Siting Regulations Section 1769(a) (1) (A), this section includes a complete description of each of the proposed project modifications as well as the necessity for the changes.

2.1 Proposed Project Changes

Following PG&E's acquisition of the CC8 project, it was determined that several significant project design features associated with the 2001 District and CEC permit approvals would require modifications. The significant physical changes that did not require modifications to the BAAQMD ATC were addressed in PG&E's December 2006 Petition to Amend, which was approved by the Commission on August 1, 2007. PG&E now requests that the following changes be made to the project's air quality-related conditions:

- Revise emission limits to reflect current Best Available Control Technology (BACT) requirements, to provide operational flexibility related to PG&E system requirements, and to reflect experience of other owner/operators with similar generating units; and
- Change the equipment description for two auxiliary units.

The proposed changes to the project design include the following:

- Change the allowable emission limits for the gas turbines during startup operations;
- Reduce the permitted hourly emission rates for NOx and PM_{10} and increase the allowable ammonia slip limit, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Reduce the annual average allowable sulfur content of the natural gas;
- Reduce the permitted hourly emission rates and increase the annual emission limit for CO, based on current BACT and operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience;
- Replace the permitted natural gas-fired gas preheater with a smaller gas dewpoint heater and increase allowable daily hours of operation; and
- Replace the motor driven fire water pump with a 300 hp Diesel fire pump.

These design changes are discussed in greater detail below.

2.1.1 Revise Emission Limits

Revise emission limits to reflect current Best Available Control Technology (BACT) requirements. Since the project was licensed and permitted in 2001, the short-term emission limits for NOx and CO that are considered BACT for natural gas-fired gas turbines have become more stringent. In this amendment, PG&E proposes to reduce the hourly NOx and CO emissions from the current limits of 2.5 ppmvd @ 15% O_2 (ppmc) and 6.0 ppmc, respectively, to 2.0 ppmc and 4.0 ppmc, respectively.[1] These changes will reduce emissions from the gas turbines/HRSGs under normal operating conditions.

In conjunction with reducing the NOx limit, PG&E is also proposing to include a provision allowing a limited number of short-term excursions above the limit to deal with short-term events that cause turbine-out NOx emissions to be elevated to levels that exceed the SCR system's ability to maintain compliance with the 2 ppmc NOx limit on a one-hour average basis. This excursion language has been included in many permits issued for gas turbines since 2001, when NOx limits became extremely stringent and averaging periods were reduced to one hour.

Finally, PG&E proposes to increase the allowable ammonia slip level from 5 ppmc to 10 ppmc in conjunction with the reduced NOx level.

Revise emission limits during startup/shutdown periods. The original CC8 permit included separate conditions for hot and cold gas turbine startups and for shutdowns. PG&E has reviewed the operating experience of other GE 7FA combined-cycle gas turbines and proposes to replace the existing limits with two sets of limits, one on a pound-per-hour basis and one on a pound-per-startup basis. The most significant change is a proposed increase in the CO emissions limit during startup, which also results in an increase in annual CO emissions from the project.

Reduce PM_{10} emission limits during duct firing and annual average sulfur content limit for natural gas. To provide maximum operational flexibility for the generating units without increasing annual SO_2 and PM_{10} emissions, PG&E is proposing to reduce the PM_{10} emission limit during duct firing from 13 lb/hr to 12 lb/hr and to reduce the allowable annual average sulfur content of the natural gas fuel from 1 gr/100 scf to 0.75 gr/100 scf (the short-term fuel sulfur limit of 1 gr/100 scf will not be affected by the proposed change).

Revise emission limits applicable during the commissioning period. PG&E has reviewed the experiences of other facilities during commissioning activities and has determined that higher daily CO and POC emissions than those allowed under the current conditions are likely to be required.

[1] The NOx emissions limit is a 1-hour average limit; the CO limit is a 3-hour average limit.

2.1.2 Changes to the Equipment Description for Auxiliary Units

Substitute a smaller gas dewpoint heater for the originally permitted fuel gas heater. In the original CC8 permit, a 12 MMBtu/hr fuel gas heater was proposed that would be used only while the gas turbines were being started up. PG&E expects to use the heater up to 24 hours per day, but has determined that a 6.5 MMBtu/hr heater is large enough to accomplish the required fuel gas preconditioning.

Replace the motor driven fire water pump with a 300 hp Diesel fire pump. The original project design called for an electric motor-driven fire water pump. However, PG&E believes that a Diesel engine-driven fire pump will be more reliable in case of emergency.

2.2 Necessity of Proposed Change

Sections 1769 (a)(1)(B) and 1769(a)(1)(C) of the CEC Siting Regulations require a discussion of the necessity for the proposed changes to the project and whether this modification is based on information that was known by the petitioner during the certification proceeding. During the licensing period, the changes to the project design proposed in this amendment were not known. Specifically, the project was designed to the BACT limits in effect at the time, and there was a limited amount of operating experience with these large, highly controlled gas turbine units on which to base emissions estimates. Further, the plant was designed and permitted by a different owner/operator as part of a larger, base load power plant. PG&E has reevaluated the potential operations of the plant based on its current and future system needs and as a stand-alone facility. The proposed changes described in this amendment will allow PG&E to minimize future permitting and economic uncertainty, and increase the operational reliability of the GGS facility.

3.0 Environmental Analysis of the Project Changes

The changes to the conditions of certification for the GGS project proposed in this amendment will increase long-term operational reliability of the facility while allowing the project to be operated in compliance with its conditions. PG&E has also filed an application with the BAAQMD to change corresponding conditions of the ATC.

The following disciplines will not be affected by the changes in this amendment and are not addressed:

- Land Use
- Worker Health and Safety
- Noise
- Socioeconomics
- Soils and Water
- Traffic and Transportation
- Waste Management
- Geologic Hazards and Resources
- Biological Resources
- Cultural Resources
- Paleontological Resources
- Hazardous Materials Management
- Water Resources
- Visual Resources

Disciplines that have the potential for environmental effects, different from those addressed in the Commission Decision (dated May 2001) and subsequent amendments, are analyzed below.

3.1 Air Quality

The potential changes to the project will affect only the air quality analysis used to support the Commission Decision for the project. Potential air quality effects of these changes are presented in Attachment A, the application to the BAAQMD for modifications to the authority to construct. Attachment A presents an estimate of the proposed emission increases and decreases, an ambient air quality impact analysis, and a demonstration of compliance with applicable air quality regulations. The proposed changes in conditions of certification affect mainly short-term NOx and CO emissions. PG&E is not proposing to change any of the existing annual air emissions limits for any pollutant other than CO.

3.2 Public Health

The only changes to the project that have the potential to affect public health are:

- The proposed increase in allowable ammonia slip level from 5 ppmc to 10 ppmc; and
- The addition of the Diesel fire pump engine.

A revised screening health risk assessment, which reflects these proposed changes to the facility, is presented in Appendix C to Attachment A (the application to the BAAQMD).

3.3 Cumulative Impacts

The cumulative impacts study area associated with the proposed changes includes the geographic area within a 6-mile radius of the GGS project and the Mirant-owned Contra Costa power plant. No new significant cumulative impacts are expected from the proposed changes relative to those presented in 00-AFC-1. These changes will not alter the assumptions or conclusions made in the Commission Decision for the CC8 project.

3.3.1 Cumulative Air Quality Impacts

For the original proceeding, the CEC made the finding that because the air quality impacts of the project were adequately mitigated and not significant, there would be no cumulative air quality impacts from the project. The proposed amendments do not change that conclusion.

3.4 LORS

The proposed revisions will not change the discussion presented in 00-AFC-1. These changes will not alter the assumptions or conclusions made in the Commission Decision and in fact will enhance the project's ability to comply with its conditions of certification.

4.0 Proposed Modifications to the Conditions of Certification

Consistent with the requirements of CEC Siting Regulations Section 1769 (a)(1)(A), this section includes proposed modifications to the project's Conditions of Certification that need to be reviewed and approved by the CEC concurrent with the CEC review of this amendment. Attachment B contains the proposed revisions to the Air Quality Conditions of Certification for the GGS project. The corresponding revisions to conditions of the BAAQMD Authority to Construct are shown in Appendix D of the BAAQMD application for modifications that is included here as Attachment A. These proposed revisions reflect the changes specified in Section 2 of this amendment.

5.0 Potential Effects on the Public

Consistent with the CEC Siting Regulations Section 1769(a)(1)(G), this section discusses the proposed project modification effects on the public.

The proposed changes at the project site will have no noticeable effects on the public. With the exception of CO, the proposed modification will not increase annual air emissions. The infrequent, short-term changes to the air emissions are shown to have ambient air impacts similar to the air quality impacts used during licensing by the Commission. There are no significant public health impacts from the proposed changes. Visual and noise impacts will be negligible and will remain characteristic of the surrounding industrial land uses. The proposed changes will not affect the public.

6.0 List of Property Owners

Consistent with the CEC Siting Regulations Section 1769(a)(1)(H), the property owners affected by the proposed modifications are listed in Attachment C.

7.0 Potential Effects on Property Owners

Consistent with the CEC Siting Regulation Section 1769(a)(1)(I), this section addresses potential effects of the proposed changes on nearby property owners, the public, and parties in the application proceedings.

The proposed increases in CO and ammonia emissions from GGS will have no noticeable effects on the nearby property owners.

Attachment A

Application to the BAAQMD for Modifications to the Authority to Construct (Air Quality Analysis and Screening Health Risk Assessment)

Pacific Gas and Electric Company
Power Generation
Fossil Plant Construction

Gateway Generating Station
3225 Wilbur Ave.
Antioch, CA 94509
(925) 459-7200

December 18, 2007
GGS-L-00041C

Jack Broadbent
Executive Officer and APCO
Bay Area Air Quality Management District
939 Ellis Street
San Francisco, CA 94109

Re: Application for Modifications to Authority to Construct
Gateway Generating Station - Plant No. 18143

Dear Mr. Broadbent:

PG&E is pleased to submit this application for modifications to the authority to construct (ATC) for the Gateway Generating Station in Antioch. The ATC for the project (formerly the Contra Costa Unit 8 Power Project) was originally issued on July 24, 2001, following certification by the California Energy Commission (CEC) on May 30, 2001. Construction of the facility started late in 2001 and was suspended in February 2002, with approximately 7 percent of construction completed. The ATC, which has been renewed three times (in 2003, 2005 and 2007) was transferred to PG&E in January 2007 under the new project name. PG&E restarted construction of the Gateway Generating Station on February 5, 2007, and anticipates that first fire of the first gas turbine will occur on August 29, 2008.

Following its acquisition of the project, PG&E evaluated the facility as originally permitted and determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. The proposed modifications are described in detail in the attached application support document.

Forms P-101B, C, ICE, P, A and HRSA are attached, and supplemental information regarding the proposed project is provided in the enclosed application support document. The filing fee and initial fee payment will be submitted to the District under separate cover. A separate application is being submitted to the CEC, as required under the conditions of the project's CEC license.

If you have any questions regarding the proposed project, please do not hesitate to call me or Nancy Matthews of Sierra Research at (916) 444-6666.

Sincerely,

Thomas Allen

Thomas Allen
Project Manager

attachments
cc: Teresa DeBono, PG&E
Andrea Grenier, Grenier & Associates, Inc.
Scott Galati, Galati & Blek
Nancy Matthews, Sierra Research
Regional Administrator, USEPA Region 9

Application to the
Bay Area Air Quality Management District
for
Modifications to the Authority to Construct
for the
Gateway Generating Station
Antioch, CA

prepared for:

Pacific Gas & Electric Company

December 2007

prepared by:

Sierra Research, Inc.
1801 J Street
Sacramento, California 95814
(916) 444-6666

APPLICATION TO THE
BAY AREA AIR QUALITY MANAGEMENT DISTRICT
FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT
FOR THE GATEWAY GENERATING STATION
ANTIOCH, CALIFORNIA

Prepared for:

Pacific Gas & Electric Company

December 2007

Prepared by:

Sierra Research, Inc.
1801 J Street
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SUMMARY

Pacific Gas & Electric Company (PG&E) completed the acquisition of Contra Costa Unit 8 (CC8) from Mirant Delta, LLC in late 2006 and subsequently received approval from the California Energy Commission to change the name of the project to the Gateway Generating Station. The Bay Area Air Quality Management District (District) has transferred the Authorities to Construct (ATCs) for the Gateway Generating Station project to PG&E. PG&E has evaluated the facility as originally permitted and has determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. With this application, PG&E is proposing to make the following changes to the permitted facility:

- Eliminate the 10-cell wet cooling tower and replace it with a dry cooling system, including an exempt wet surface air cooler;
- Replace the permitted natural gas-fired preheater with a smaller dewpoint heater and increase allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup operations;
- Reduce the permitted hourly emission rates for NOx, CO and PM_{10}, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Increase the daily and annual emission rates for CO, based on operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 hp Diesel fire pump at the facility.

These changes will require the following types of changes to the permit conditions:

- Eliminate conditions related to the wet cooling tower;
- Revise conditions related to the natural gas-fired preheater;
- Revise conditions related to emission limits during startup;
- Reduce allowable hourly NOx, CO and PM_{10} emission limits for the Gas Turbines and Heat Recovery Steam Generators (HRSGs);
- Increase allowable daily and annual CO emission limits for the Gas Turbines and HRSGs;
- Revise the commissioning limits; and
- Revise the requirements related to emissions offsets.

This application support document discusses the proposed modifications, presents revised emissions calculations and ambient air quality modeling results, demonstrates the project's continued compliance with all applicable rules and regulations, and provides proposed revisions to the permit conditions. The only annual emissions increase proposed in this application is for

CO. Since the proposed annual increase in CO emissions is above the PSD significance threshold, the proposed modification is subject to PSD review for CO.

APPLICATION TO THE BAY AREA AIR QUALITY MANAGEMENT DISTRICT FOR MODIFICATIONS TO THE AUTHORITY TO CONTRUCT FOR GATEWAY GENERATING STATION ANTIOCH, CALIFORNIA

TABLE OF CONTENTS

Page

SUMMARY i

PART I. PROJECT DESCRIPTION 1

A. Applicant's Name and Business Description........ 1

B. Type of Application 1

C. Description of the Proposed Project 2

D. Project Emissions........ 3

1. Emissions from the Gas Turbines and HRSGs 3
2. Emissions from the Turbine Cooling System 6
3. Emissions from the Dewpoint Heater 7
4. Emissions from the Diesel Fire Pump Engine 8
5. Fuel Use Limits for Permitted Equipment 8
6. Total Emissions for the Facility........ 9
7. Noncriteria Pollutant Emissions 10
8. Commissioning Emissions........ 12

PART II. DEMONSTRATION OF REGULATORY COMPLIANCE 13

A. Regulation 2, Rule 2: New Source Review 13

1. Best Available Control Technology 13
2. Offset Requirements 14
3. Ambient Air Quality Modeling Requirements 14

B. Screening Health Risk Assessment........ 15

C. Other District Rules and Regulations 16

1. Regulation 1, Section 301: Public Nuisance ... 16

2. Regulation 2, Rule 1, Sections 301 and 302: Authority to Construct and Permit to Operate ... 17

3. Regulation 2, Rule 3: Power Plants ... 17

4. Regulation 2, Rule 6: Major Facility Review ... 17

5. Regulation 2, Rule 7: Acid Rain ... 17

6. Regulation 6: Particulate Matter and Visible Emissions ... 17

7. Regulation 7: Odorous Substances ... 18

8. Regulation 8: Organic Compounds ... 18

9. Regulation 9: Inorganic Gaseous Pollutants ... 18

D. Other Federal Requirements ... 18

1. New Source Performance Standards ... 18

2. National Emissions Standards for Hazardous Air Pollutants ... 19

Part III. PSD Ambient Air Quality Impact Analysis ... 20

A. Air Quality Modeling Methodology ... 20

B. Air Quality Impact Analysis ... 22

1. Screening Analysis for Turbines/HRSGs ... 22

2. Refined Air Quality Impact Analysis ... 24

3. Results of the Ambient Air Quality Modeling Analysis ... 27

C. Total Ambient Air Quality Impacts ... 27

LIST OF TABLES

Page

1. Maximum Pollutant Emissions Rates, Each Gas Turbine 3
2. Maximum Pollutant Emission Rates, Each Turbine with Duct Burners 4
3. Maximum Emission Rates During Turbine Startup 4
4. Maximum Pollutant Emission Rates Natural Gas-Fired Dewpoint Heater 7
5. Maximum Pollutant Emission Rates Emergency Diesel Fire Pump Engine 8
6. Hourly, Daily, and Annual Fuel Use 9
7. Emissions from Facility Equipment 9
8. Noncriteria Pollutant Emissions for the Gas Turbines with Duct Firing 11
9. Emission Limits for the Commissioning Period 12
10. Applicability of BACT to the Gas Turbines/HRSGs 13
11. Summary of Offset Requirements 14
12. Comparison of GGS Cumulative Emissions Increase with PSD Trigger Levels 15
13. Screening Health Risk Assessment Results 16
14. Compliance with 40 CFR 60 Subpart KKKK 19
15. Turbine Operating Conditions for Screening Analysis 22
16. Results of Turbine Screening Procedure: Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period 23
17. Summary of Results from Redefined Modeling Analysis for Permitted Sources 26
18. Modeled Maximum Project Impacts 27

LIST OF FIGURES

1. Facility Layout 21

2. Layout of the Receptor Grid 24

LIST OF APPENDICES

A. Emissions Calculations

B. Modeling Parameters

C. Screening Health Risk Assessment

D. Revised Permit Conditions

PART I. PROJECT DESCRIPTION

A. Applicant's Name and Business Description

Name: Pacific Gas & Electric Company

Address: 3225 Wilbur Avenue
Antioch, CA 94509

Contact: Tom Allen, Project Manager
(925) 459-7200

Mailing Address for Permits:

Same as above, with copy to:

Sierra Research
1801 J Street
Sacramento, CA 95811

General Business Description: Electric generation

Responsible Official:

John S. Keenan, Senior VP Generation and CNO
Pacific Gas & Electric Company

Air Quality Consultants:

Sierra Research
1801 J Street
Sacramento, CA 95811
Contact: Nancy Matthews
(916) 444-6666

Type of Use Entitlement: PG&E will own and operate the project.

Estimated Construction Date: Construction of the permitted units is underway, in accordance with the existing Authority to Construct. Construction of the exempt units (including the air-cooled condenser in place of the cooling tower) is also underway. Construction of the proposed modifications to permit units, the dewpoint heater and fire pump engine, is expected to begin upon issuance of the revised Authority to Construct.

B. Type of Application

This is an application for modification to existing Authorities to Construct.

C. Description of the Proposed Project

The Gateway Generating Station Project (formerly Contra Costa Unit 8, or CC8) was permitted to consist of the following equipment:

- S-41 and S-43: Two Combustion Gas Turbines, General Electric Frame 7FA Model PG 7231 or equivalent; equipped with dry low-NOx combustors, abated by selective catalytic reduction systems and oxidation catalysts;
- S-42 and S-44: Two Heat Recovery Steam Generators (HRSGs), equipped with low-NOx duct burners, abated by selective catalytic reduction systems and oxidation catalysts;
- S-46: One 10-cell wet cooling tower;
- S-45: One natural gas-fired preheater; and
- S-48: One oil-water separator.

PG&E proposes to make several changes to the Gateway Generating Station Project (GGS) permit, as follows:

- Eliminate S-46, the 10-cell wet cooling tower, and replace it with an air-cooled condenser and a wet surface-air cooler, both of which are exempt from District permitting requirements;
- Replace the permitted natural gas-fired preheater, S-45, with a smaller unit and increase its allowable daily hours of operation;
- Change the allowable emission rates for the gas turbines during startup and shutdown operations;
- Reduce the permitted hourly mass emission and concentration limits for NOx, CO and PM_{10}, based on current BACT and operating experience;
- Change the ammonia slip limit;
- Reduce the permitted PM_{10} emissions for the project;
- Increase the permitted daily and annual CO emissions for the project to reflect the revised CO startup emission rates;
- Revise the allowable CO and POC emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Add a 300 kW Diesel fire pump engine.

As a result of these proposed changes, PG&E is requesting permit condition changes that will reflect the revised emission rates and operating conditions for the permitted units. The overall increases in allowable CO emissions from the facility will trigger PSD review for that pollutant. Because the cooling tower is being eliminated, annual PM_{10} emissions, and therefore the facility's PM_{10} offset obligations, will be reduced.

D. Project Emissions

This section of the application presents an assessment of the emissions from the revised PG&E project design. These revisions include reducing the NOx and CO emissions from the gas turbines and HRSGs to reflect current BACT; reducing the PM_{10} emission limit for the units during duct firing; changing the ammonia slip limit; eliminating the wet cooling tower and associated PM_{10} emissions; and adding a new Diesel-fueled fire pump engine. The analysis of the new project design also includes reductions in NOx and increases in CO from the gas turbines during startup.

1. Emissions from the Gas Turbines and HRSGs

The gas turbine and duct burner emission rates have been estimated from vendor data, current BACT limits, new maximum fuel consumption rates, and established emission calculation procedures. The changes in emissions are a result of: (1) the proposed reductions in NOx, CO and PM_{10} concentrations and mass emission limits during normal operations; and (2) revised emission rates and operating assumptions for the turbines during startup. The maximum emission rates for the combustion turbines alone and for the combustion turbines with duct burners are shown in Tables 1 and 2, respectively. The emission data and operating parameters that are the basis for these emission rates are shown in Appendix A, Table A-1. Proposed new emission limits during turbine startup are shown in Table 3.

Table 1
Maximum Pollutant Emission Rates
Each Gas Turbine[1]

Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr[2]
NOx	2.0[3] (2.5)	0.0072 (0.009)	13.40
SO_2[4]	0.57	0.0028	5.22
CO	4.0[3] (6.0)	0.0088 (0.0132)	16.31
POC	2.0[3]	0.0017	4.67
PM_{10}[5]	--	--	11.0
NH_3	10 (5)	--	24.80

Notes:
1. Emission rates shown reflect the highest value at any operating load, without duct firing. Numbers in parentheses show current limit where changes are proposed.
2. Current ATC does not include lb/hr limits for the CTGs without duct firing.
3. Current BACT.
4. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
5. 100% of particulate matter emissions assumed to be emitted as PM_{10}/$PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.

Table 2 Maximum Pollutant Emission Rates Each Turbine with Duct Burners[1]			
Pollutant	ppmvd @ 15% O_2	lb/MMBtu	lb/hr
NOx	2.0[2] (2.5)	0.0072 (0.009)	15.18 (20)
SO_2[3]	0.57	0.0028	5.92 (6.18)
CO	4.0[2] (6.0)	0.0088 (0.0132)	18.49 (29.22)
POC	2.0[2]	0.0017	5.29 (5.6)
PM_{10}[4]	--	--	12(13)
NH_3	10 (5)	--	28.10

Notes:
1. BAAQMD permit limit. Numbers in parentheses show current limit where changes are proposed.
2. Current BACT.
3. Based on maximum fuel sulfur content of 1 grain per 100 standard cubic feet.
4. 100% of particulate matter emissions assumed to be emitted as $PM_{10}/PM_{2.5}$; PM_{10} emissions include both front and back half as those terms are used in USEPA Method 5.

Table 3 Maximum Emission Rates During Turbine Startup (Each Turbine)[1]			
	NOx	CO	POC
Cold Start, lb/hour	160 (n/a)	900 (n/a)	16 (n/a)
Cold Start, lb/start[2]	600 (452)	5,400 (990)	96 (109)
Hot Start, lb/start[3]	160 (189)	900 (291)	16 (26)

Notes:
1. Estimated based on operating experience for other 7FA CTGs in combined cycle. See Appendix A, Table A-1. Numbers in parentheses show current limit where changes are proposed.
2. Maximum of six hours per cold start.
3. Maximum of one hour per hot start.

The current permit conditions include separate emissions limits for cold startup, hot startup and shutdown. PG&E proposes to eliminate these separate limits and replace them with a single set of limits expressed in units of pounds per hour and pounds per startup. The proposed pounds per startup limit assumes a maximum of six hours for a full cold start.

Components of the gas turbine combustor assemblies must be replaced periodically because these components have a limited operational life. After the new gas turbine combustor components are installed, each gas turbine's fuel system must be tuned to meet the manufacturer's specifications for emissions and acoustic dynamics. During this tuning process the turbines must operate at low loads intermittently for up to six hours with potentially elevated emission rates. Combustor tuning activities would also be covered by the proposed startup emission limits.

NOx Emissions Excursions

In the experience of many operators of gas turbines that are controlled to extremely low NOx levels using dry low-NOx combustors, there are some short-term turbine operating conditions that may cause temporarily elevated NOx levels. During these brief periods, the turbine-out NOx emissions are elevated to levels that exceed the SCR system's ability to maintain compliance with the 2 ppmc NOx limit on a one-hour average basis. PG&E requests that the District include in the revised permit a condition that allows a limited number of excursions above the 2 ppmc limit so that these conditions that are beyond the operator's control will not be considered violations of the permitted emissions limit. This excursion language has been included in many permits issued for gas turbines since 2001, when NOx limits became extremely stringent and averaging periods were reduced to one hour. The proposed condition language is as follows:

> *Compliance with the hourly NOx emission limits specified in Condition 20a shall not be required during short-term excursions of less than 10 hours per rolling 12-month period.*
>
> *Short-term excursions are defined as 15-minute periods designated by the applicant, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2 ppmvd corrected to 15% O_2. Maximum 1-hour average NOx concentrations for periods that include short-term excursions shall not exceed 30 ppmvd corrected to 15% O_2. All emissions during short-term excursions shall be included in all calculations of daily and annual mass emissions required by this permit.*

Ammonia Slip Limit

PG&E is also proposing to change the ammonia slip limit from 5 ppmvd @ 15% O_2 (ppmc), as specified in Condition 20e, to 10 ppmc. This request is made in conjunction with reducing the NOx limit from 2.5 ppmc to 2.0 ppmc on a 1-hour average basis. Although the previous owner of the project had agreed to meet a 5 ppmc ammonia slip limit, that limit was combined with a 2.5 ppmc NOx limit. Because of the additional demands on the NOx control system to achieve a 2.0 ppmc NOx limit, it would be extremely difficult to maintain continuous compliance with a 5 ppmc ammonia slip limit. The screening health risk assessment provided in Section II.B demonstrates that there are no significant public health impacts associated with the 10 ppmc ammonia slip level.

Moreover, we do not believe there is an air quality basis for requiring a lower ammonia slip level for the project. In a previous FDOC for a project in the Bay Area, the BAAQMD staff stated:[1]

> *…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.*

The assessment of ammonia emissions and the screening health risk assessment in the CC8 FDOC were based on an ammonia slip limit of 10 ppmvd, so the proposed change will not affect the analyses presented there. However, by agreement of the original applicant, the limit was changed in the final permit conditions from 10 ppmvd to 5 ppmvd.

2. Emissions from the Turbine Cooling System

PG&E has eliminated wet cooling from the project design and is using an air-cooled condenser (ACC) system instead. Components of the wet cooling system that will no longer be required and have therefore been eliminated from the original project design include the water supply pipeline, wet cooling tower, surface condenser, associated convenience systems, and the cooling tower chemical treatment system. New components to support the ACC system include a condensate polishing system, a new water supply source, and a wastewater discharge source. There are no air emissions associated with the ACC system.

The project as permitted incorporated evaporative cooling on the combustion turbine air inlets. However, due to the change in the project's water supply, PG&E proposes to eliminate this option and replace the evaporative cooling system with an electric chiller system. There are no air emissions associated with the electric chiller system.

In addition to the changes in the cooling water system, PG&E has also reviewed the water demand of the combustion turbine's steam power augmentation (PAG) systems. As a result of this review, PG&E has determined that the water demand and economic implications do not warrant implementing PAG on the combustion turbines.

Finally, PG&E has determined that a small fin-fan heat exchanger in combination with a wet surface air cooled (WSAC) heat exchanger system will be used to provide the necessary heat rejection capacity for auxiliary plant systems. The proposed fin-fan system is similar to the ACC system. The WSAC system is a hybrid between a wet cooling tower and fin-fan heat exchanger, and uses water sprayed over the heat transfer bundles to increase the cooling capacity of the system.

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[1] Final Determination of Compliance, East Altamont Energy Center LLC, July 10, 2002, p. 12.

Based on the conservatively high operating assumptions shown in Appendix A, Table A-2, emissions from the WSAC will be less than 1 lb/hr and 1 tpy. In the WSAC process, the warm process water is cooled in a closed-loop tube bundle so the process water being cooled never comes in contact with the outside air. Therefore, the WSAC is exempt from permitting under BAAQMD Rule 2, Section 2-1-128.4 ("Water cooling towers and water cooling ponds not used for evaporative cooling of process water, or not used for evaporative cooling of water from barometric jets or from barometric condensers").[2]

3. Emissions from the Dewpoint Heater

The current version of the ATC includes a natural gas-fired fuel gas preheater (dewpoint heater) rated at 12 MMBtu/hr. The ATC includes a condition limiting daily heat input to the fuel gas preheater to 192 MMBtu/day, effectively restricting the heater to 16 hours per day of operation. PG&E anticipates the need to operate the dewpoint heater up to 24 hours a day under some ambient conditions, so is proposing to substitute a smaller unit rated at approximately 6.5 MMBtu/hr (HHV). Specifications for the dewpoint heater are shown in Appendix A, Table A-3. Emissions from the replacement heater are shown in Table 4.

Table 4
Maximum Pollutant Emission Rates
Natural Gas-Fired Dewpoint Heater

Pollutant	ppmvd @ 3% O_2[1]	lb/MMBtu (HHV)[1]	lb/hr[2]	lb/day[3]
NOx	50	0.060	0.39	9.4
SO_2[4]	--	0.0028[4]	0.018	0.4
CO	40	0.029	0.19	4.6
POC	5.5	0.0045	0.029	0.7
PM_{10}	--	0.0074	0.048	1.2

Notes:
1. Performance from manufacturer at rated load.
2. Manufacturer's not-to-exceed emission rate.
3. Based on 24 hours per day of operation.
4. SO_2 emissions in lb/MMscf, based on natural gas sulfur content of 1 gr/100 scf.

[2] Rule 2, Section 2-1-128 exempts sources listed in the subsection, "provided that the source does not require permitting pursuant to Section 2-1-319." Section 2-1-319 requires permitting of sources with emissions in excess of 5 tpy.

4. Emissions from the Diesel Fire Pump Engine

PG&E is also proposing to install a 300 bhp emergency Diesel driven fire pump engine at GGS. The fire pump engine will be Tier 2-certified and will meet the requirements of the ARB Air Toxics Control Measure. Operation of the fire pump engine for testing and maintenance will be limited to one hour per day and 50 hours per year. Hourly and annual emissions from the Diesel fire pump engine are summarized in Table 5. Specifications for the fire pump engine are provided in Attachment A, Table A-4.

Table 5
Maximum Pollutant Emission Rates
Emergency Diesel Fire Pump Engine

Pollutant	g/bhp-hr[1]	lb/hr	tons/yr[2]
NOx	4.36	2.88	0.1
SO_2[3]	--	0.0029	<0.01
CO	0.32	0.21	<0.1
POC	0.29	0.19	<0.1
PM_{10}[4]	0.12	0.08	<0.1

Notes:
1. Based on manufacturer's specifications for Clarke Model JU6H-UF40 Tier 2 fire pump engine.
2. Based on 50 hours per year of operation for testing and maintenance, per the ATCM.
3. Based on the use of ultra-low sulfur CARB Diesel fuel with maximum sulfur content of 15 ppm.

5. Fuel Use Limits for Permitted Equipment

The maximum heat input rates (fuel consumption rates) for the gas turbines and duct burners are shown in Table 6.

Table 6 Hourly, Daily, and Annual Fuel Use[1]			
Units	Dewpoint Heater	Gas Turbines plus Duct Burners, each[2]	Total Fuel Use, all units[3]
MMBtu/hr	6.5 (12)	2094.4 (2227)	4,195.3
MMBtu/day	156 (192)[4]	50,265.6 (49,950)	100,687.2
MMBtu/yr	56,940	34,900,000[5]	34,956,940

Notes:
1. Numbers in parentheses show current permit limit where changes are proposed. MMBtu are HHV.
2. Based on maximum heat input for full load turbine operation at 23° F plus duct burner for maximum daily operation; based on full load turbine operation at 60° F plus duct burner, maximum of 22.5 hours per day and 5100 hours per year per duct burner for annual operation.
3. Includes S-41, S-42, S-43, S-44 and S-45.
4. Daily limit from ATC Condition 47.
5. Annual limit for both CTG trains, from ATC Condition 16.

6. Total Emissions for the Facility

The maximum annual, daily, and hourly emissions proposed for GGS are shown in Table 7. Detailed emissions calculations from the individual permit units are shown in Appendix A, Table A-5. Although the calculations of daily and annual emissions of NOx, SO_2 and POC show that emissions from the facility after the proposed permit changes are expected to be lower than the levels originally permitted for CC8, PG&E is not proposing to change the annual emission limits for these pollutants.

Table 7 Emissions from Facility Equipment					
	NOx	SO_2	CO	POC	PM_{10}
Maximum Hourly Emissions, lb/hr					
Turbines and Duct Burners[1]	175.2	11.8	918.5	21.3	22.0
Dewpoint Heater	0.4	<0.1	0.2	<0.1	<0.1
Fire Pump Engine[2]	2.9	<0.1	0.2	0.2	0.1
Total Project, pounds per hour[3]	178.5	11.9	918.9	21.5	24.3
Original Analysis[4]	170	12.4	541	109	26
Maximum Daily Emissions, lb/day					
Turbines and Duct Burners[1]	1,746.6	284.0	11,465.6	382.6	576.0
Dewpoint Heater	9.4	<0.1	4.6	0.7	1.2
Fire Pump Engine[2]	2.9	<0.1	0.2	0.2	0.1

Table 7 Emissions from Facility Equipment					
	NOx	SO_2	CO	POC	PM_{10}
Total Project, pounds per day[3]	1,759.0	284.0	11,470.3	384.4	577.2
Current Permit Limits[5]	1,994	297	3,602	468	624
Permit Limits After Modification, lb/day	**1,994**	**297**	**11,470.3**	**468**	**577.2**
Maximum Annual Emissions, tpy					
Turbines and Duct Burners[1]	149.6	37.0	554.3	45.3	101.5
Dewpoint Heater	1.7	0.1	0.8	0.1	0.3
Fire Pump Engine	0.1	<0.1	<0.1	<0.1	<0.1
Total Project, tons per year[3]	151.4	37.0	555.1	45.4	101.7
Current Permit Limits[5]	174.3	48.5	259.1	46.6	112.2[6]
Permit Limits After Modification, tpy	**174.3**	**37.0**	**555.1**	**46.6**	**101.7**

Notes:

1. Includes startup emissions.
2. Calculations reflect one hour per day and 50 hours per year of operation for the fire pump for testing and maintenance.
3. Numbers may not add directly due to rounding.
4. Appendix B of the FDOC, turbines and duct burners only. NOx, POC and CO emissions shown are emission rates during startup. SO_2 and PM_{10} emissions reflect duct firing.
5. Current daily permit limit applies to gas turbines and HRSGs only; annual permit limit applies to all permitted units.
6. Current PM_{10} limit includes wet cooling tower, which is being eliminated in this amendment.

7. <u>Noncriteria Pollutant Emissions</u>

The noncriteria pollutants that may be emitted from the gas turbines and HRSGs at GGS, and their respective emission factors, are shown in Table 8. Noncriteria pollutant emissions from the dewpoint heater, which total 6.3 lb/yr, are shown in detail in Table A-7, Appendix A. Diesel particulate matter (DPM) emissions from the Diesel fire pump engine will not exceed 4.0 lb/yr, based on 50 hours per year of operation for testing and maintenance.

Table 8
Noncriteria Pollutant Emissions for the Gas Turbines with Duct Firing[1]

Pollutant	Emission Factor (lb/MMscf)	Emissions	
		lb/hr, each	ton/yr, total (two trains)
Acetaldehyde	4.08×10^{-2}	0.084	0.7
Acrolein	3.69×10^{-3}	0.0076	6.4×10^{-2}
Ammonia[2]	--[3]	28.1	238.9
Benzene	3.33×10^{-3}	0.0069	5.7×10^{-2}
1,3-Butadiene	4.39×10^{-4}	0.0009	7.6×10^{-3}
Ethylbenzene	3.26×10^{-2}	0.068	0.6
Formaldehyde	3.67×10^{-1}	0.76	6.3
Hexane	2.59×10^{-1}	0.54	4.5
Naphthalene	1.66×10^{-3}	0.0034	2.8×10^{-2}
Other PAHs[4]	1.79×10^{-4}	0.0004	3.1×10^{-3}
Propylene[2]	7.71×10^{-1}	1.60	13.3
Propylene Oxide	2.98×10^{-2}	0.006	0.5
Toluene	1.33×10^{-1}	0.28	2.3
Xylene	6.53×10^{-2}	0.14	1.1
Total HAPs			**16.2**

Notes:
1. See Appendix A, Table A-8 for source of emission factors and basis of calculations.
2. Ammonia and propylene are not HAPs.
3. Ammonia emissions calculated from 10 ppm ammonia slip rate.
4. Includes benzo(a)anthracene, benzo(a)pyrene, benzo(b)fluoranthene, benzo(k)fluoranthene, chrysene, dibenzo(a,h)anthracene, and indeno(1,2,3-cd)pyrene

8. Commissioning Emissions

Based on a review of commissioning experiences at other large turbine projects, PG&E is proposing changes in some of the emission limits for the commissioning period in the ATC. The current permit limits and the proposed new limits are shown in Table 9 below.

Table 9
Emission Limits for the Commissioning Period

	Current Limits		Proposed Limits	
Pollutant	lb/day	lb/hr	lb/day	lb/hr
NOx	8,400	400	no change	no change
CO	13,000	584	40,000	4,000
POC	535	--[1]	1,600	--
PM_{10}	624	--	432	--
SO_2	297	--	no change	--

Note:
1. No limit in current permit.

PART II. DEMONSTRATION OF REGULATORY COMPLIANCE

This section summarizes the applicable BAAQMD rules and regulations and describes how the proposed modification will comply with these requirements.

A. Regulation 2, Rule 2: New Source Review

The new source review requirements that are applicable to the proposed modification are:

- Best Available Control Technology (BACT) requirements (Rule 2-2-301);
- Offset requirements (Rules 2-2-302 and 2-2-303); and
- Ambient air quality impact analysis (Rule 2-2-305.2).

PSD air quality analysis requirements (Rule 2-2-305.2) are applicable because the CO emissions increases resulting from the proposed modifications will be above the PSD *de minimis* level (see Section III).

1. Best Available Control Technology

Rule 2-2-301 requires the application of BACT to an emissions unit with emissions in excess of 10 pounds per day. Table 10 compares the emissions from the gas turbines/HRSGs to the 10 lb/day threshold and shows the corresponding BACT determinations.

Table 10
Applicability of BACT to the Gas Turbines/HRSGs

Pollutant	Emissions per Train, lb/day	BACT
NOx	873.3	SCR (2.0 ppmc, 1-hour avg)
SO_2	142.0	natural gas fuel
CO	5,732.8	oxidation catalyst (4.0 ppmc, 3-hour avg)
POC	191.3	oxidation catalyst (2.0 ppmc, 3-hour avg)
PM_{10}	288.0	natural gas fuel

The District made BACT determinations for the facility when the Authority to Construct was issued in 2001, and PG&E has reviewed the current BACT requirements that would be applicable were the facility to be permitted now. While the control technology proposed for the original permit still constitutes BACT, the NOx and the CO emission concentration levels considered to be BACT have been reduced. GGS is proposing to reduce the permitted hourly

NOx and CO emission concentrations and mass emission rates during normal operation to reflect current BACT.

As shown in Tables 4 and 5, emissions from the natural gas-fired dewpoint heater and the Diesel fire pump engine will be less than 10 lb/day, so these units are not subject to BACT requirements.

2. Offset Requirements

Rule 2-2-302 requires POC and NOx emission reduction credits to be provided for facilities that will emit 10 tons per year or more. If the facility will emit 35 tons per year or more on a pollutant-specific basis, the offsets must be provided at a ratio of 1.15:1.0. Offsets must be provided at a ratio of 1.0:1.0 if emissions are between 10 and 35 tons per year.

Rule 2-2-303 requires emissions offsets for emissions increases at facilities that emit more than 100 tons per year of SO_2 and PM_{10}. If required, these offsets must be provided at a ratio of 1.0:1.0.

Table 11 below summarizes the offset requirements for the proposed modification. The table shows the facility emissions after the modifications, the offset requirements under Rules 2-2-302 and 2-2-303, the offsets provided for the original application, and the remaining offsets required.

Table 11
Summary of Offset Requirements

Pollutant	Total Facility Emissions (tpy)	Offset Ratio	Total Offsets Required (tpy)	Offsets Provided for CC8	Offsets to be Refunded (tpy)
NOx	174.3	1.15:1.0	200.5	200.5[1]	0
POC	46.6	1.15:1.0	53.6	53.6[1]	0
PM_{10}	101.7	1.0:1.0	101.7	112.2[2]	10.5

Notes:
1. NOx and POC ERCs from Banking Certificate #693 (Gaylord Container, Antioch).
2. PM_{10} offsets were provided in the form of SO_2 ERCs at a ratio of 3:1. The SO_2 ERCs were from Banking Certificates #693 (Gaylord Container, Antioch), #694 (PG&E, Martinez) and #695 (Hudson ICS, San Leandro).

3. Ambient Air Quality Modeling Requirements

Pursuant to the Prevention of Significant Deterioration (PSD) requirements of New Source Review (Regulation 2-2-304.2 and 2-2-305.2), a major modification to a major facility must perform modeling to assess the net air quality impact of that pollutant, if the cumulative increase minus the contemporaneous emission reduction credits at the facility exceed maximum annual pollutant emissions in excess of the trigger levels shown in Table 12. Under Regulation 2-2-605.4, the baseline emission rate used to determine the contemporaneous emission reduction credits is equal to the emission cap that has been fully offset by the facility.

Table 12
Comparison of GGS Cumulative Emissions Increase with PSD Trigger Levels

	Emissions, tons per year			
Pollutant	GGS Proposed Emissions	CC8 Emissions, as permitted and fully offset[1]	Net Increase (Decrease)	PSD Trigger
NOx	174.3	174.3	--	40
SO_2	37.0	0[2]	37.0	40
CO	555.1	0[2]	555.1	100
POC	46.6	46.6	--	40
PM_{10}	101.7	112.2	(10.5)	15

Notes:
1. From Table C-1 of the FDOC.
2. No offsets were required or provided for SO_2 and CO emissions from CC8.

Since the cumulative increases in CO emissions exceed the PSD trigger level of 100 tpy, an ambient air quality impact analysis must be performed for CO. The required ambient air quality impacts analysis is provided in Part III of this application.[3]

B. Screening Health Risk Assessment

Pursuant to the BAAQMD Risk Management Policy, a health risk screening must be executed to determine the potential impact on public health resulting from the worst-case emissions of toxic air contaminants (TACs) from the proposed project. In accordance with the requirements of the Reg. 2, Rule 5 (Toxics New Source Review) and CAPCOA guidelines, the impact on public health due to the emission of these compounds was assessed utilizing air pollutant dispersion models.

The screening health risk assessment prepared for the CC8 project showed that the carcinogenic and chronic risks from the project as approved would be below significant impact thresholds. While PG&E proposes to increase allowable annual ammonia emissions from the CTGs and HRSGs by increasing the allowable ammonia slip from 5 ppm to 10 ppm, the original screening health risk assessment was based on 10 ppm ammonia slip so the proposed change will not affect

[3] Because this amendment includes increases in short-term NOx emissions during commissioning, the ambient air quality impact analysis also includes an evaluation of short-term NO_2 impacts from the project.

that conclusion. In fact, by eliminating the wet cooling tower, the potential health risk from the project would be reduced. However, since the proposed modifications to the approved facility include the addition of a Diesel fire pump engine and Diesel particulate matter (DPM) is considered a toxic air contaminant, a new screening health risk assessment has been prepared that includes the Diesel fire pump engine. The results of the revised screening health risk assessment are presented in Table 13. A detailed discussion of the screening health risk assessment procedures and assumptions is provided in Appendix C to this application.

Table 13
Screening Health Risk Assessment Results

Source	Carcinogenic Risk (in one million)	Chronic Health Hazard Index	Acute Health Hazard Index
Gas Turbines and HRSGs, Dewpoint Heater	0.16	0.01	0.09
Diesel Fire Pump Engine	0.96	<0.01	n/a
Total, All Sources	1.04	0.01	0.09

The maximum cancer risk from the facility, which is due mainly to the Diesel particulate matter emissions from the fire pump engine, is slightly higher than 1 in one million. Since the fire pump engine PM emissions comply with the 0.1 g/bhp-hr level considered toxics BACT (T-BACT), the risk is considered acceptable. In addition, the area where the cancer risk is predicted to exceed 1 in one million is limited to receptors at the southeast fenceline of the plant property.

C. Other District Rules and Regulations

In the Final Determination of Compliance issued for CC8 in February 2001, the District staff determined that the facility would comply with all other applicable District rules and regulations. The proposed modifications in this application do not change the District's conclusions regarding the applicable rules and regulations or the compliance of the gas turbines, HRSGs and dewpoint heater. The compliance of the facility, including the proposed Diesel fire pump engine, is summarized in this section.

1. <u>Regulation 1, Section 301: Public Nuisance</u>

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.

2. 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, PG&E has submitted an application to the District to obtain a modified Authority to Construct and Permit to Operate for the proposed S-41 & S- 43 Gas Turbines, S-42 & S-44 Heat Recovery Steam Generators, S-45 Fuel Preheater, S-48 Oil Water Separator and S-50 Diesel Fire Pump Engine.

3. Regulation 2, Rule 3: Power Plants

Because the GGS has already received its license from the California Energy Commission, the District's review does not fall under the requirements of Regulation 2, Rule 3.

4. Regulation 2, Rule 6: Major Facility Review

Pursuant to Regulation 2, Rule 6, section 404.1, PG&E has submitted a Major Facility Review application for the facility as originally permitted. An amended MFR permit application will be submitted to reflect the modifications proposed in this application.

5. Regulation 2, Rule 7: Acid Rain

The GGS 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), GGS must submit an Acid Rain Permit Application to the District at least 24 months prior to the date on which each unit commences operation. The required Acid Rain Permit Application was submitted to the District and to EPA in December 2006.

6. Regulation 6: Particulate Matter and Visible Emissions

Through the use of dry low-NOx 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. In the DOC for the original project, the District staff determined that the grain loading resulting from the simultaneous operation of each power train would comply with the grain loading limit. Since PG&E is proposing to reduce the PM_{10} emissions from the gas turbines and HRSGs during duct firing, the compliance margin will be even greater.

7. Regulation 7: Odorous Substances

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

8. Regulation 8: Organic Compounds

This facility is exempt from Regulation 8, Rule 2, "Miscellaneous Operations" per 8-2-110 since natural gas will be fired exclusively in the GGS gas turbines and duct burners.

9. Regulation 9: Inorganic Gaseous Pollutants

- Regulation 9, Rule 1, Sulfur Dioxide
- Regulation 9, Rule 3, Nitrogen Oxides from Heat Transfer Operations
- Regulation 9, Rule 7, Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters
- Regulation 9, Rule 9, Nitrogen Oxides from Stationary Gas Turbines

The DOC for the original project made the determination that the project was in compliance with or exempt from these rules. No changes to the project are being proposed that would affect these determinations.

D. Other Federal Requirements

1. New Source Performance Standards

The federal new source performance standards (NSPS) establish standards of performance to limit the emission of criteria pollutants (air pollutants for which EPA has established national ambient air quality standards [NAAQS]) from new or modified facilities in specific source categories. The NSPS for Stationary Gas Turbines and for Stationary Compression Ignition Internal Combustion Engines will be applicable to the proposed project.

When the project was originally permitted, the gas turbines were subject to the requirements of Subpart GG. However, since the facility did not commence construction as defined under the NSPS before February 18, 2005, the requirements of Subpart KKKK are now applicable.[4]

[4] The previous owner of the project, Mirant, commenced construction under a valid ATC in 2001, but suspended construction in 2002. Because substantial use had been made of the ATC, the BAAQMD renewed the ATC in accordance with Rule 2-1-407.3. However, the NSPS defines "commence" as "undertak[ing] a continuous program of construction…or…entered into a contractual obligation to undertake and complete, within a reasonable time, a continuous program of construction…" (40 CFR 60.2) A suspension in construction of longer than 18 months is generally used by EPA to determine that construction has not been continuous.

Subpart KKKK limits NOx and SO2 emissions from new gas turbines based on power output. The limits for gas turbines greater than 30 MW are 0.39 lb NOx per MW-hr and 0.58 lb SO2 per MW-hr. The emission limits of 2.0 ppmc NOx and 0.56 ppmc SO2 proposed for GGS are well below the Subpart KKKK limits, as shown in Table 14.

Table 14
Compliance With 40 CFR 60 Subpart KKKK

Pollutant	Proposed Permit Limits			Subpart KKKK Limit, lb/MW-hr
	ppmc	lb/hr	lb/MW-hr (max)	
NOx	2.0	15.2	0.08	0.39
SO_2	0.56	5.9	0.03	0.59

Compliance with the NSPS limits must be demonstrated through an initial performance test. Because the GGS gas turbines will be equipped with continuous NOx emissions monitors, ongoing annual performance testing will not be required under the NSPS.

For the size of engine proposed for the emergency fire pump engine, Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines, requires facilities to purchase engines meeting the EPA engine non-road certification level of Tier II or better depending on the year the engine is manufactured/purchased. This regulation also requires the engines to use ultra-low sulfur content Diesel fuel.

2. National Emissions Standards for Hazardous Air Pollutants

The calculations in Section 1.D. of this application demonstrate that emissions of HAPs from the facility will be well below the major source thresholds of 10 tons per year of individual HAP or 25 tons per year of total HAPs. Therefore, the facility is not subject to the MACT requirements of the National Emissions Standards for Hazardous Air Pollutants.

Part III. PSD Ambient Air Quality Impact Analysis

As shown in Table 14 above, the cumulative increases in emissions from the proposed changes are below the PSD significant emissions thresholds for all pollutants except CO. Since the net increase in emissions of this pollutant exceeds the applicable significance threshold, a revised ambient air quality analysis is required for CO. Because changes are being proposed to the emission rates during gas turbine startup and commissioning, new startup modeling has also been carried out.

A. Air Quality Modeling Methodology

The assessment of impacts from GGS on ambient air quality has been conducted using the EPA guideline models SCREEN3 and AERMOD and three years of surface meteorological data (2004 through 2006) collected by Mirant at the Contra Costa power plant less than ½ mile from the project site.[5] Upper air data were obtained from Buchanan Field in Concord.[6] The ambient air quality impact analysis was conducted in accordance with the protocol filed with the District in August 2007 and the comments provided by the District staff in October 2007 (see Appendix B, Attachment B-1).The surface parameters developed for use in the AERMET meteorological data input are documented in Appendix B, Attachment B-2. Because the exhaust stacks are less than Good Engineering Practice (GEP) stack height, ambient impacts due to building downwash were evaluated. Impacts were evaluated in simple and complex terrain and under inversion breakup and shoreline fumigation conditions. The PV Molar Ratio Method was used to convert one-hour NOx impacts into one-hour NO_2 impacts. Figure 1 shows the layout of the facility and the location of each exhaust stack. Building dimensions used in the BPIP analysis are summarized in Table B-1 of Appendix B, and are shown in detail in the modeling files provided.

Emissions from the turbines will be exhausted from two 195-foot exhaust stacks. The project also includes emissions from the dewpoint heater with a release height of approximately 15 feet,

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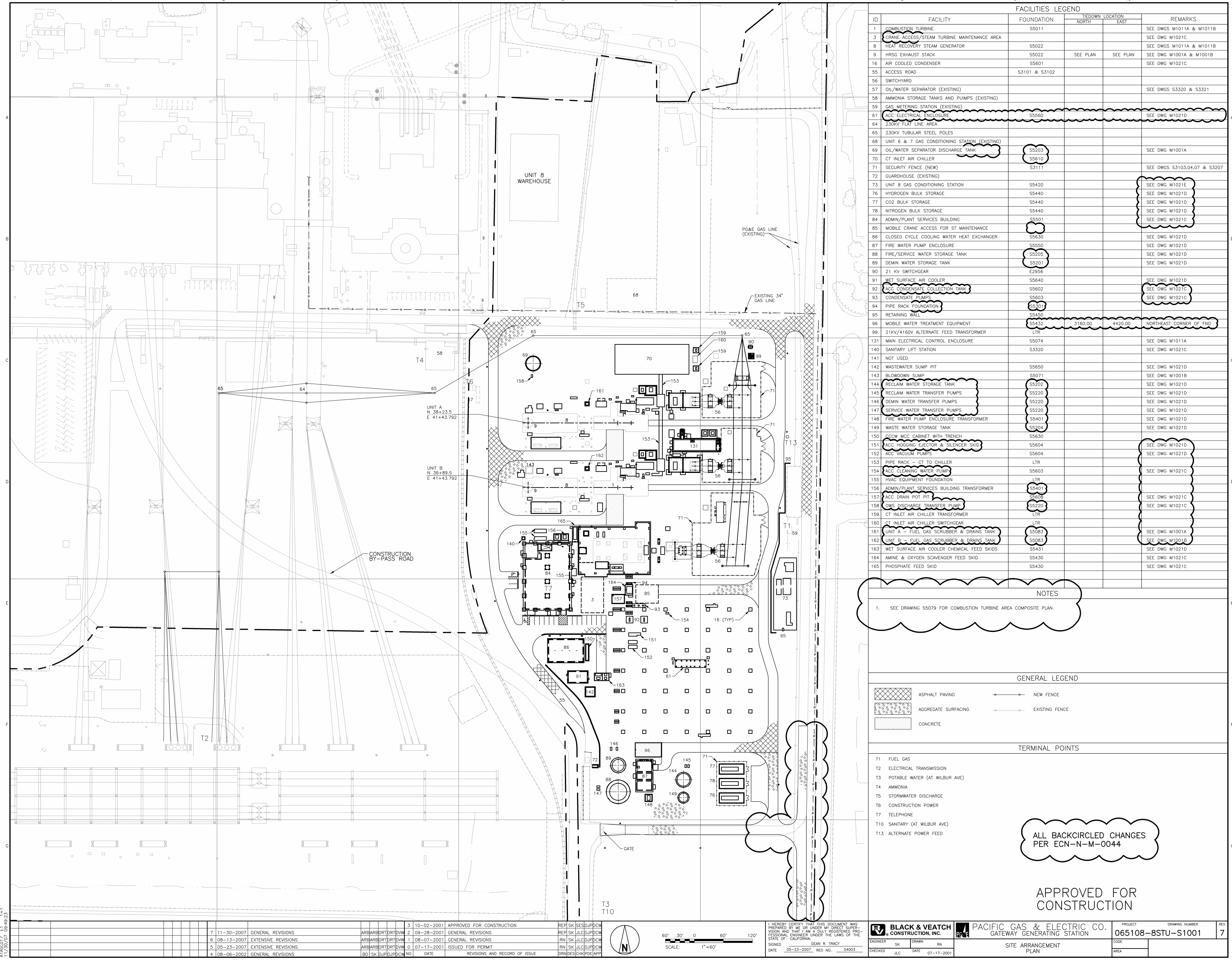
[5] The original AQIA for CC8 was carried out using ISCST3. Since that time, EPA has adopted AERMOD as a guideline model to replace ISCST3.

[6] Although BAAQMD policy to limit mixing height to 600 meters, it is not possible to impose this limit in the AERMOD modeling system.

Figure 1
Facility Layout



FACILITIES LEGEND

ID	FACILITY	FOUNDATION	TIEDOWN LOCATION NORTH	TIEDOWN LOCATION EAST	REMARKS
1	COMBUSTION TURBINE	S5011			SEE DWGS M1011A & M1011B
3	CRANE ACCESS/STEAM TURBINE MAINTENANCE AREA				SEE DWG M1021C
8	HEAT RECOVERY STEAM GENERATOR	S5022			SEE DWGS M1011A & M1011B
9	HRSG EXHAUST STACK	S5022	SEE PLAN	SEE PLAN	SEE DWG M1001A & M1001B
16	AIR COOLED CONDENSER	S5601			SEE DWG M1021C
55	ACCESS ROAD	S3101 & S3102			
56	SWITCHYARD				
57	OIL/WATER SEPARATOR (EXISTING)				SEE DWGS S3320 & S3321
58	AMMONIA STORAGE TANKS AND PUIMPS (EXISTING)				
59	GAS METERING STATION (EXISTING)				
61	ACC ELECTRICAL ENCLOSURE	S5560			SEE DWG M1021D
64	230KV FLAT LINE AREA				
65	230KV TUBULAR STEEL POLES				
68	UNIT 6 & 7 GAS CONDITIONING STATION (EXISTING)				
69	OIL/WATER SEPARATOR DISCHARGE TANK	S5203			SEE DWG M1001A
70	CT INLET AIR CHILLER	S5610			
71	SECURITY FENCE (NEW)	S3111			SEE DWGS S3103,04,07 & S3207
72	GUARDHOUSE (EXISTING)				
73	UNIT 8 GAS CONDITIONING STATION	S5420			SEE DWG M1021E
76	HYDROGEN BULK STORAGE	S5440			SEE DWG M1021D
77	CO2 BULK STORAGE	S5440			SEE DWG M1021D
78	NITROGEN BULK STORAGE	S5440			SEE DWG M1021D
84	ADMIN/PLANT SERVICES BUILDING	S5501			SEE DWG M1021C
85	MOBILE CRANE ACCESS FOR ST MAINTENANCE				
86	CLOSED CYCLE COOLING WATER HEAT EXCHANGER	S5630			SEE DWG M1021D
87	FIRE WATER PUMP ENCLOSURE	S5550			SEE DWG M1021D
88	FIRE/SERVICE WATER STORAGE TANK	S5205			SEE DWG M1021D
89	DEMIN WATER STORAGE TANK	S5201			SEE DWG M1021D
90	21 KV SWITCHGEAR	E2956			
91	WET SURFACE AIR COOLER	S5640			SEE DWG M1021D
92	ACC CONDENSATE COLLECTION TANK	S5602			SEE DWG M1021C
93	CONDENSATE PUMPS	S5603			SEE DWG M1021C
94	PIPE RACK FOUNDATION	S5301			
95	RETAINING WALL	S5450			
96	MOBILE WATER TREATMENT EQUIPMENT	S5432	3160.00	4420.00	NORTHEAST CORNER OF FND
99	21KV/4160V ALTERNATE FEED TRANSFORMER	LTR			
131	MAIN ELECTRICAL CONTROL ENCLOSURE	S5074			SEE DWG M1011A
140	SANITARY LIFT STATION	S3320			SEE DWG M1021C
141	NOT USED				
142	WASTEWATER SUMP PIT	S5650			SEE DWG M1021D
143	BLOWDOWN SUMP	S5071			SEE DWG M1001B
144	RECLAIM WATER STORAGE TANK	S5202			SEE DWG M1021D
145	RECLAIM WATER TRANSFER PUMPS	S5220			SEE DWG M1021D
146	DEMIN WATER TRANSFER PUMPS	S5220			SEE DWG M1021D
147	SERVICE WATER TRANSFER PUMPS	S5220			SEE DWG M1021D
148	FIRE WATER PUMP ENCLOSURE TRANSFORMER	S5401			SEE DWG M1021D
149	WASTE WATER STORAGE TANK	S5204			SEE DWG M1021D
150	CCCW MCC CABINET WITH TRENCH	S5630			
151	ACC HOGGING EJECTOR & SILENCER SKID	S5604			SEE DWG M1021D
152	ACC VACUUM PUMPS	S5604			SEE DWG M1021D
153	PIPE RACK – CT TO CHILLER	LTR			
154	ACC CLEANING WATER PUMP	S5603			SEE DWG M1021C
155	HVAC EQUIPMENT FOUNDATION	LTR			
156	ADMIN/PLANT SERVICES BUILDING TRANSFORMER	S5401			
157	ACC DRAIN POT PIT	S5608			SEE DWG M1021C
158	OWS DISCHARGE TRANSFER PUMP	S5220			SEE DWG M1021C
159	CT INLET AIR CHILLER TRANSFORMER	LTR			
160	CT INLET AIR CHILLER SWITCHGEAR	LTR			
161	UNIT A – FUEL GAS SCRUBBER & DRAINS TANK	S5083			SEE DWG M1001A
162	UNIT B – FUEL GAS SCRUBBER & DRAINS TANK	S5083			SEE DWG M1001B
163	WET SURFACE AIR COOLER CHEMICAL FEED SKIDS	S5431			SEE DWG M1021D
164	AMINE & OXYGEN SCAVENGER FEED SKID	S5430			SEE DWG M1021C
165	PHOSPHATE FEED SKID	S5430			SEE DWG M1021C

the wet surface air cooler with a release height of approximately 19 feet, and the small Diesel fire pump engine with a release height of 10 feet 8 inches.[7]

B. Air Quality Impact Analysis

1. Screening Analysis for Turbines/HRSGs

The original permit application had identified 11 different likely operating conditions for the turbines and HRSGs that reflect a range of operating temperatures and loads, with and without the duct burners in operation. With the elimination of PAG and modifications to the duct firing capability of the units, the 11 operating conditions have been reduced to eight conditions, which are summarized below in Table 15. Emission rates and stack parameters for these operating conditions are shown in Appendix B, Table B-2.

Table 15
Turbine Operating Conditions for Screening Analysis

Condition Number	Turbine Load	Ambient Temp, deg. F	Duct Firing?	Inlet Air Chilling?
1	100%	30	no	no
2	50%	30	no	no
3	100%	60	no	yes
4	50%	60	no	yes
5	100%	60	yes	yes
6	100%	100	no	yes
7	50%	100	no	yes
8	100%	100	yes	yes

To ensure that impacts were evaluated under the operating conditions that produced the highest ambient impacts, a screening procedure was used to determine the inputs to the refined modeling. These operating cases were screened for worst-case ambient impacts on a pollutant- and averaging period-specific basis using the AERMOD model and the meteorological data described above. The results of the turbine screening analysis are presented in Appendix B, Table B-3, and are summarized in Table 16. The stack parameters and emissions rates for the turbine operating condition that produced the maximum modeled impact for each pollutant and averaging period were then used in the refined modeling analysis to evaluate the modeled impacts of the project

[7] Although the WSAC is exempt from District permitting, it has been included in the AQIA for completeness.

Table 16 Results of Turbine Screening Procedure: Turbine Operating Conditions Producing Maximum Modeled Ambient Impacts by Pollutant and Averaging Period		
Pollutant/Averaging Period		Operating Case
NOx and CO	1 hour (startup only)	Case 4
NOx, CO, SO_2 and PM_{10}	1, 3 and 8 hours 24 hours (SO_2 only) annual	Case 5
PM_{10}	24 hours	Case 7

for that pollutant and averaging period. Although only short-term NO_2 and CO impacts are required to be evaluated, all pollutants and averaging times have been included in the AQIA.

The screening analysis included both simple and complex terrain and accounted for downwash conditions at the facility. Terrain features were taken from USGS DEM data and 7.5-minute quadrangle maps of the area. For the turbine screening analysis, the coarse Cartesian grids of receptors from the original analysis were used.

2. Refined Air Quality Impact Analysis

The operating conditions and emission rates used to model GGS are shown in Table B-4, Appendix B. As discussed above, the turbine stack parameters used in modeling the impacts for each pollutant and averaging period reflected the worst-case screening analysis.

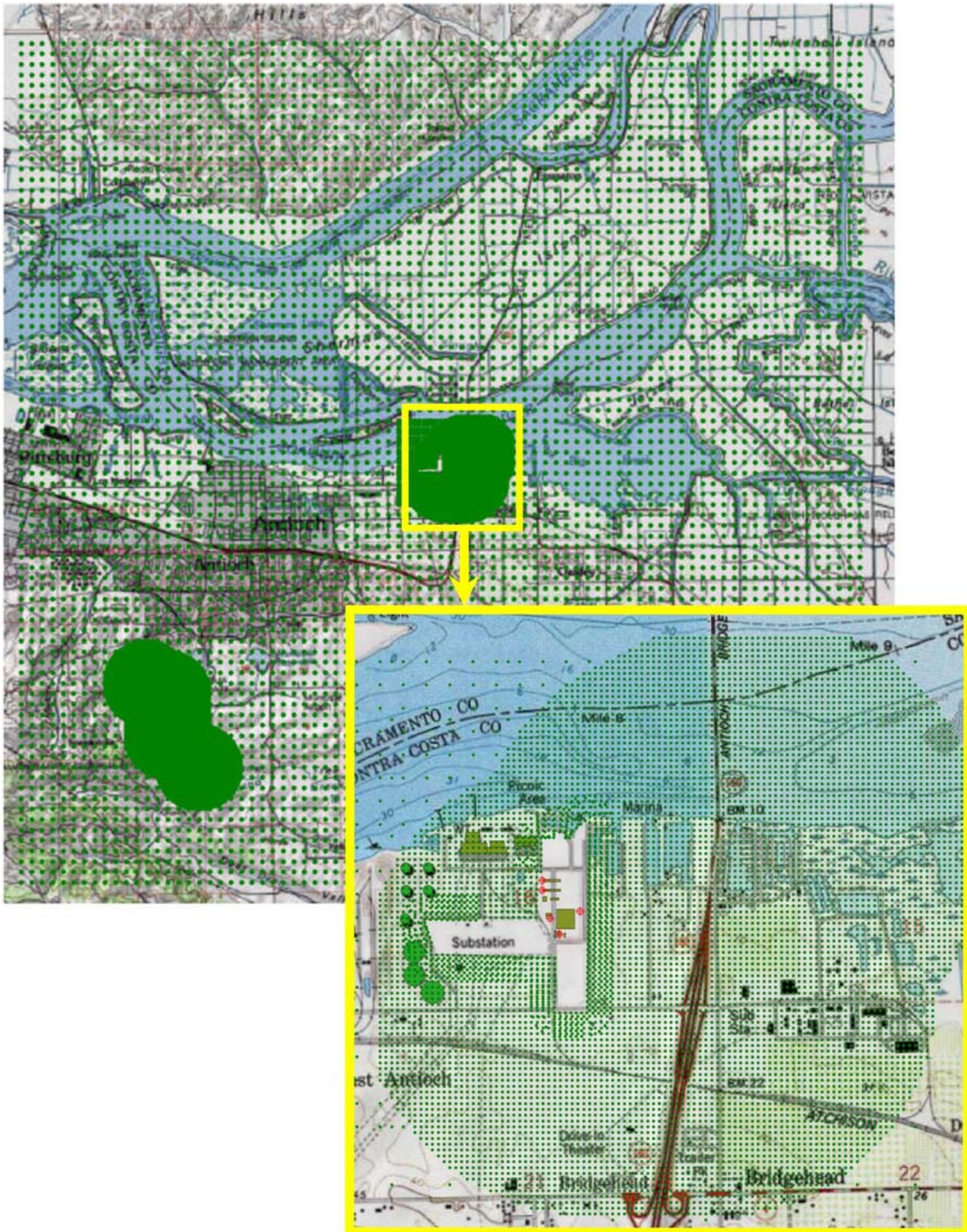
The receptor grids were derived from 7.5 minute DEM data. Twenty-five by 25 meter refined receptor grids were used in areas where the coarse grid analysis indicated modeled maxima would be located. Figure 2 shows the layout of the receptor grid.

Emissions from the permitted units were also modeled under inversion breakup fumigation and shoreline fumigation conditions, as well as during startup and commissioning, to ensure that the worst-case impacts are evaluated. These specialized air quality modeling analyses are discussed in more detail below.

Inversion Breakup Fumigation

Fumigation occurs when a stable layer of air lies a short distance above the release point of a plume and unstable air lies below. Under these conditions, an exhaust plume may be drawn to the ground, causing high ground-level pollutant concentrations. Although fumigation conditions rarely last as long as one hour, relatively high ground-level concentrations may be reached during that time.

Figure 2
Layout of the Receptor Grid



The SCREEN3 model was used to evaluate maximum ground-level concentrations for short-term averaging periods (24 hours or less). Since SCREEN3 is a single-source model, each source was modeled separately and the maximum modeled concentrations were added together regardless of their locations. This approach is believed to overestimate the predicted concentrations under inversion breakup fumigation conditions.

Calculation of inversion breakup fumigation impacts is shown in Appendix B, Table B-5.

Shoreline Fumigation Modeling

Shoreline fumigation modeling was conducted to determine the impacts as a result of overwater plume dispersion. Because land surfaces tend to both heat and cool more rapidly than water, shoreline fumigation tends to occur on sunny days when the denser cooler air over water displaces the warmer, lighter air over land. During an inland sea breeze, the unstable air over land gradually increases in depth with inland distance. The boundary between the stable air over the water and the unstable air over the land and the wind speed determine if the plume will loop down before much dispersion of the pollutants has occurred. SCREEN3 can examine sources within 3000 meters of a large body of water, and was used to calculate the maximum shoreline fumigation impact. The model uses a stable onshore flow and a wind speed of 2.5 meters per second; the maximum ground-level shoreline fumigation concentration is assumed by the model to occur where the top of the stable plume intersects the top of the well-mixed thermal inversion boundary layer (TIBL). The model TIBL height was varied in accordance with BAAQMD procedures (between 2 and 6) to determine the highest shoreline fumigation impact. The worst-case (highest) impact was used in determining facility impacts due to shoreline fumigation. Based on the analysis performed for the original CC8 project, shoreline fumigation was assumed to persist for a maximum of 180 minutes, and the impacts on all short-term averaging periods were assessed. Calculation of shoreline fumigation impacts is shown in Appendix B, Table B-6.

Turbine Startup

Facility impacts were also modeled during the startup of one turbine to evaluate short-term impacts under startup conditions. Emission rates during startup were based on an engineering analysis of available data, which included source test data from startups of the GE gas turbines at Los Medanos Energy Center and Moss Landing Power Plant. Turbine exhaust parameters for the minimum operating load point (50%) were used to characterize turbine exhaust during startup. Startup impacts were evaluated for the 1-hour averaging period using AERMOD.[8] Calculation of startup impacts is shown in more detail in Appendix B, Table B-7.

Turbine Commissioning

During commissioning, one or both of the CTGs may operate without emission controls while the CTGs and HRSGs are being tuned and tested. Commissioning impacts were evaluated for both the 1- and 8-hour averaging periods using AERMOD. Calculation of commissioning impacts is shown in more detail in Appendix B, Table B-8.

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[8] Modeling for CO impacts for the 8-hour averaging period include startup.

3. Results of the Ambient Air Quality Modeling Analysis

The maximum facility impacts modeled for each of the analyses described above are summarized in Table 17 below. Highest 1-hour average NO_2 and CO impacts are expected to occur during the brief periods when the fire pump is being tested.

Table 17
Summary of Results from Refined Modeling Analysis for Permitted Sources

Pollutant	Averaging Time	Modeled Concentration ($\mu g/m^3$)			
		Normal Operation[1]	Inversion Breakup Fumigation[2]	Shoreline Fumigation[2]	Startup
NO_2	1 hour	146.8	6.3	40.3	104.9
	annual	3.4	n/a	n/a	n/a
SO_2	1 hour	9.8	2.4	15.7	n/a
	3 hours	4.8	2.2	14.1	n/a
	24 hours	1.0	1.0	1.6	n/a
	annual	0.12	n/a	n/a	n/a
CO	1 hour	51.4	7.7	49.1	926
	8 hours	292.5	5.4	16.2	n/a[3]
PM_{10}	24 hours	4.0	2.3	3.9	n/a
	annual	1.4	n/a	n/a	n/a

Notes:
1. Includes fire pump. Without fire pump, maximum 1-hour average NO_2 concentration is 68 ug/m^3.
2. Inversion breakup and shoreline fumigation are short-term phenomena and do not affect annual impacts.
3. Included in 8-hour impacts for normal operations.

C. Total Ambient Air Quality Impacts

The maximum facility impacts including the exempt sources are summarized in Table 18 below. To determine the maximum ground-level impacts on ambient air quality for comparison with the applicable state and federal ambient air quality standards, modeled worst-case impacts were added to maximum existing pollutant concentrations in the area. Maximum ground-level impacts for allowable operation of the facility are shown together with the ambient air quality standards in Table 18.

Table 18
Modeled Maximum Project Impacts[1]

Pollutant	Averaging Time	Maximum Facility Impact[1] (μg/m³)	Background[2] (μg/m³)	Total Impact (μg/m³)	State Standard (μg/m³)	Federal Standard (μg/m³)
NO_2	1 hour	151.8	109	260.8	338[3]	--
	annual	3.4	20.8	24.2	56[3]	100
SO_2	1 hour	16	117	133	655	--
	3 hours	14	65.0	79	--	1300
	24 hours	1.6	26.3	27.9	105	365
	annual	0.1	5.3	5.4	--	80
CO	1 hour	926	5,125	6,051	23,000	40,000
	8 hours	293	2,133	2,426	10,000	10,000
PM_{10}	24 hours	4.0	64.0	68	50	150
	annual	1.4	21.7	22.1	20	--

Notes:
1. See Note 1, Table 15.
2. Background concentrations reflect highest monitored concentrations from Pittsburg and Bethel Island monitoring stations, 2004-2006.
3. The ARB amended the Nitrogen Dioxide ambient air quality standard February 22, 2007, to lower the 1-hr standard to 0.18 ppm and establish a new annual standard of 0.030 ppm. These changes will become effective after regulatory changes are submitted and approved by the Office of Administrative Law.

Appendix A

Emissions Calculations

Table A-1
Gateway Generating Station
Emissions and Operating Parameters for CTGs

Case	Cold Base	Cold Low	Avg. Base	Avg. Low	Avg. Peak	Hot Base	Hot Low	Hot Peak
Turbine Load, MW	192.7		181.4		181.4	181.4		181.4
Ambient Temp, F	30	30	60	60	60	100	100	100
Turbine Load, %								
Chiller On/Off	Off	Off	On	On	On	On	On	On
CTG heat input, MMBtu/hr (HHV	1848.1	1209.0	1848.1	1271.9	1848.1	1848.1	1114.0	1848.1
DB heat input, MMBtu/hr (HHV)	0.0	0.0	0.0	0.0	246.3	0.0	0.0	246.3
Total heat input, MMBtu/hr (HHV	1848.1	1209.0	1848.1	1271.9	2094.4	1848.1	1114.0	2094.4
Stack flow, lb/hr	3,371,393	2,205,562	3,391,353	2,334,098	3,120,398	3,446,840	2,077,733	3,171,163
Stack flow, acfm	928,011	607,104	936,640	644,642	865,245	960,629	579,061	887,192
Stack flow, dscfm	689,649	451,167	689,649	474,650	624,466	689,649	415,716	624,466
Stack temp, F	180	180	180	180	180	180	180	180
Stack exhaust, vol %								
O2 (dry)	13.00%	13.00%	13.00%	13.00%	11.00%	13.00%	13.00%	11.00%
CO2 (dry)	4.52%	4.52%	4.52%	4.52%	5.65%	4.52%	4.52%	5.65%
H2O	8.54%	8.54%	9.38%	9.38%	11.17%	11.64%	11.64%	13.37%
Emissions								
NOx, ppmvd @ 15% O2	2.0	2.0	2.0	2.0	2.0	2.0	2.0	2.0
NOx, lb/hr	13.40	8.76	13.40	9.22	15.18	13.40	8.08	15.18
NOx, lb/MMBtu	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072	0.0072
SO2, ppmvd @ 15% O2	0.56	0.56	0.56	0.56	0.56	0.56	0.56	0.56
SO2, lb/hr (short-term)	5.22	3.42	5.22	3.59	5.92	5.22	3.15	5.92
SO2, lb/MMBtu (short-term)	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028	0.0028
SO2, lb/hr (long-term)	3.92	2.56	3.92	2.69	4.44	3.92	2.36	4.44
SO2, lb/MMBtu (long-term)	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021	0.0021
CO, ppmvd @ 15% O2	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
CO, lb/hr	16.31	10.67	16.31	11.23	18.49	16.31	9.83	18.49
CO, lb/MMBtu	0.0088	0.0088	0.0088	0.0088	0.0100	0.0088	0.0088	0.0100
POC, ppmvd @ 15% O2	2.00	2.00	2.00	2.00	1.60	2.00	2.00	2.00
POC, lb/hr	4.67	3.06	4.67	3.22	4.23	4.67	2.82	5.29
POC, lb/MMBtu	0.0025	0.0025	0.0025	0.0025	0.0023	0.0025	0.0025	0.0029
PM10, lb/hr	11.0	11.0	11.0	11.0	12.0	11.0	11.0	12.0
PM10, lb/MMBtu	0.0060	0.0091	0.0060	0.0086	0.0065	0.0060	0.0099	0.0065
PM10, gr/dscf	0.00186	0.00284	0.00186	0.00270	0.00224	0.00186	0.00309	0.00224
NH3, ppmvd@15% O2	10.0	10.0	10.0	10.0	10.0	10.0	10.0	10.0
NH3, lb/hr	24.80	16.22	24.80	17.07	28.10	24.80	14.95	28.10

Table A-2
Gateway Generating Station
Calculation of Wet SAC Emissions

Typical Worst-Case Design Parameters	
Water Flow Rate, 10E6 lbm/hr	2.59
Water Flow Rate, gal/min	5,180
Drift Rate, %	0.0030
Drift, lbm water/hr	77.67
PM10 Emissions based on TDS Level	
TDS level, ppm (based on 5 COC)	2500
PM10, lb/hr	0.19
PM10, lb/day	4.7
PM10, tpy	0.85

Based on 8760 hrs/yr

Table A-3
Gateway Generating Station
Emissions for Dewpoint Heater

Fuel Gas Flow, MMBtu/hr (HHV)	6.5
Fuel Gas Flow, scfh	6418
Exhaust Flow Rate, acfm	1964
Stack Gas Temperature, deg F	300
Stack Diameter, inches	7.981
Emissions	
NOx, ppmvd @ 3% O2 (1)	50
NOx, lb/MMBtu (HHV) (1)	0.060
CO, ppmvd @ 3% O2 (1)	40
CO, lb/MMBtu (HHV) (1)	0.029
POC, ppmvd @ 3% O2 (1)	5.5
POC, lb/MMBtu (HHV) (1)	0.0045
PM10, lb/MMBtu (HHV) (1)	0.0074
SO2, lb/MMscf (3)	2.86
NOx, lb/hr (2)	0.392
CO, lb/hr (2)	0.191
POC, lb/hr (2)	0.029
PM10, lb/hr	0.048
SO2, lb/hr	0.018

Notes:
1. Manufacturer specification at rated heater capacity.
2. Manufacturer guarantee
3. Calculated from sulfur content of natural gas
   (<1 gr/100 scf)

Table A-4
Gateway Generating Station
Diesel Fire Pump Performance and Emissions

Engine		
Fire Pump Mfr		Clarke
Engine Mfr		John Deere
Model		JU6H-UF40
Useable Horsepower	hp	300
Speed	rpm	2100
Fuel		CA Diesel
Specific Gravity		0.825
Fuel Sulfur Content	wt %	0.0015%
Fuel Consumption	gph	14
	Btu/bhp-hr	0
Exhaust Flow	acfm	1740
Stack Velocity	ft/sec	13.4
Exhaust Temperature	deg. F	770
Exhaust Pipe Diameter	in	6.065
Exhaust Stack Height	ft	10.67
Pump		
Speed	rpm	2100
Capacity	gpm	2500
Pump Efficiency	%	74
Brake Horsepower	bhp	300
Operating Profile		
Annual Operation	hrs	50
Emissions		
	g/bhp-hr	lb/hr
NOx	4.36	2.88
CO	0.32	0.21
ROC	0.29	0.19
PM10	0.12	0.08
SO2	--	0.0029

Diesel fuel	7.00	lb/gal
	136,903	Btu/gal

Table A-5
Gateway Generating Station
Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

Assumptions for Daily and Annual Ops:	**Startup/ Shutdown Hours**	**Duct Firing Hours**	**Base Load Hours**	
NOx, POC, CO	6	18	0	per day
CO	520	4380	324	per year
NOx, POC	365	5840	1825	per year
SOx, PM10	0	24	0	per day
	0	5100	3660	per year

Equipment	max. hour	NOx (lbs/hr)	SOx (lbs/hr) short-term	SOx (lbs/hr) annual avg	CO (lbs/hr)	POC (lbs/hr)	PM10 (lbs/hr)	NH3 (lbs/hr)
Gas Turbine 1, base	0	13.40	5.22	3.92	16.31	4.67	11.00	24.80
Gas Turbine 2, base	0	13.40	5.22	3.92	16.31	4.67	11.00	24.80
Gas Turbine 1, peak	1	15.18	5.92	4.44	18.49	5.29	12.00	28.10
Gas Turbine 2, peak	0	15.18	5.92	4.44	18.49	5.29	12.00	28.10
Gas Turbine 1, startups/shutdowns	0	100.00	5.22	n/a	900.00	16.00	11.00	24.80
Gas Turbine 2, startups/shutdowns	1	100.00	5.22	n/a	900.00	16.00	11.00	24.80
Dewpoint Heater	1	0.39	1.83E-02	1.38E-02	0.19	0.03	0.05	0
WSAC	1	0.00	0.00	n/a	0.00	0.00	0.19	0
Diesel Fire Pump Engine	1	2.88	2.94E-03	n/a	0.21	0.19	0.08	0

Detailed Calculations for Maximum Hourly, Daily, and Annual Criteria Pollutant Emissions

	NOx Emissions			SOx Emissions			CO Emissions			POC Emissions			PM10 Emissions		
Equipment	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy	Max lb/hr	Max lb/day	Total tpy
Gas Turbine 1, base	0.0	0.0	12.2	0.0	0.0	7.2	0.0	0.0	2.6	0.0	0.0	4.3	0.0	0.0	20.1
Gas Turbine 2, base	0.0	0.0	12.2	0.0	0.0	7.2	0.0	0.0	2.6	0.0	0.0	4.3	0.0	0.0	20.1
Gas Turbine 1, peak	15.2	273.3	44.3	5.9	142.0	11.3	18.5	332.8	40.5	5.3	95.3	15.5	12.0	288.0	30.6
Gas Turbine 2, peak	0.0	273.3	44.3	5.9	142.0	11.3	0.0	332.8	40.5	0.0	95.3	15.5	12.0	288.0	30.6
Gas Turbine 1, startups/shutdowns	0.0	600.0	18.3	0.0	0.0	0.0	0.0	5,400.0	234.0	0.0	96.0	2.9	0.0	0.0	0.0
Gas Turbine 2, startups/shutdowns	160.0	600.0	18.3	0.0	0.0	0.0	900.0	5,400.0	234.0	16.0	96.0	2.9	0.0	0.0	0.0
Dewpoint Heater	0.4	9.4	1.7	1.8E-02	0.4	0.1	0.2	4.6	0.8	2.9E-02	0.7	0.1	0.05	1.2	0.2
WSAC	--	--	--	--	--	--	--	--	--	--	--	--	0.2	4.7	0.9
Diesel Fire Pump Engine	2.9	2.9	0.1	2.9E-03	2.9E-03	7.4E-05	0.2	0.2	5.3E-03	0.2	0.2	0.0	0.1	0.1	2.0E-03
Total, CTGs/HRSGs only	175.2	1,746.6	149.6	11.8	284.0	36.96	918.5	11,465.6	554.3	21.3	382.6	45.3	24.0	576.0	101.5
	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy
Total Permitted Equipment	178.5	1,758.9	151.4	11.9	284.4	37.0	918.9	11,470.4	555.1	21.5	383.5	45.4	24.1	577.2	101.7
(excluding WSAC)	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy	lb/hr	lb/day	tpy
Proposed Permit		1,994.0	174.3		297.0	37.8		11,470.4	555.1		468.0	46.6		624.0	101.7
(excluding WSAC)		lb/day	tpy		lb/day	tpy		lb/day	tpy		lb/day	tpy		lb/day	tpy
Existing Permit		1,994.0	174.3		297.0	48.5		3,602.0	259.1		468.0	46.6		624.0	112.2
		lb/day	tpy		lb/day	tpy		lb/day	tpy		lb/day	tpy		lb/day	tpy

Table A-6
Gateway Generating Station
Calculation of Noncriteria Pollutant Emissions from Gas Turbines

Compound	Emission Factor, lb/MMscf (1)	Maximum Hourly Emissions, lb/hr Each CTG (2)	Maximum Hourly Emissions, lb/hr Total, 2 CTGs	Total Annual Emissions, 2 CTGs (3) lb/yr	Total Annual Emissions, 2 CTGs (3) tpy
Ammonia	(4)	28.10	56.21	468,197.8	234.1
Propylene	7.71E-01	1.60	3.19	26,588.8	13.3
Hazardous Air Pollutants					
Acetaldehyde	4.08E-02	8.44E-02	1.69E-01	1,407.0	0.70
Acrolein	3.69E-03	7.64E-03	1.53E-02	127.3	6.36E-02
Benzene	3.33E-03	6.89E-03	1.38E-02	114.8	5.74E-02
1,3-Butadiene	4.39E-04	9.09E-04	1.82E-03	15.1	7.57E-03
Ethylbenzene	3.26E-02	6.75E-02	1.35E-01	1,124.2	5.62E-01
Formaldehyde	3.67E-01	0.76	1.52	12,656.4	6.33
Hexane	2.59E-01	0.54	1.07	8,931.9	4.47
Naphthalene	1.66E-03	3.44E-03	6.87E-03	57.2	2.86E-02
PAHs (5)	4.57E-05	9.45E-05	1.89E-04	1.6	7.87E-04
Propylene oxide	2.98E-02	6.17E-02	0.12	1,027.7	0.51
Toluene	1.33E-01	2.75E-01	0.55	4,586.7	2.29
Xylene	6.53E-02	1.35E-01	0.27	2,251.9	1.13
Total HAPs			3.88	32,302.0	16.15

Notes:

(1) All factors except PAHs, hexane and propylene from AP-42, Table 3.4-1. Acrolein, benzene and formaldehyde reflect oxidation catalyst. Individual PAHs, hexane and propylene are CATEF mean results as AP-42 does not include factors for these compounds.

(2) Based on maximum hourly turbine fuel use of 2094 MMBtu/hr and fuel HHV of 1012 Btu/scf. 2.07 MMscf/hr

(3) Based on total annual fuel use of 34,900,000 MMBtu/yr and fuel HHV of 1012 Btu/scf 34,486.2 MMscf/yr

(4) Based on 10 ppm ammonia slip from SCR system.

(5) Emission factors for individual PAHs weighted by cancer risk relative to B(a)P and summed to obtain overall B(a)P equivalent emission rate for HRA.

	Mean EF	PEF Equiv.	PEF-Weighted EF
PAHs (as B(a)P)			
Benzo(a)anthracene	2.26E-05	0.1	2.26E-06
Benzo(a)pyrene	1.39E-05	1	1.39E-05
Benzo(b)fluoranthrene	1.13E-05	0.1	1.13E-06
Benzo(k)fluoranthrene	1.10E-05	0.1	1.10E-06
Chrysene	2.52E-05	0.01	2.52E-07
Dibenz(a,h)anthracene	2.35E-05	1.05	2.47E-05
Indeno(1,2,3-cd)pyrene	2.35E-05	0.1	2.35E-06

Table A-7
Gateway Generating Station
Calculation of Noncriteria Pollutant Emissions from Dewpoint Heater

Compound	Emission Factor, lb/MMscf (1)	Hourly Emissions, lb/hr (2)	Total Annual Emissions (3) lb/yr	tpy
Propylene	7.30E-01	4.69E-03	41.0	2.05E-02
Hazardous Air Pollutants				
Acetaldehyde	4.30E-03	2.76E-05	0.2	1.21E-04
Acrolein	2.70E-03	1.73E-05	0.2	7.59E-05
Benzene	8.00E-03	5.13E-05	0.4	2.25E-04
1,3-Butadiene	n/a	--	--	--
Ethylbenzene	9.50E-03	6.10E-05	0.5	2.67E-04
Formaldehyde	1.70E-02	1.09E-04	1.0	4.78E-04
Hexane	6.30E-03	4.04E-05	0.4	1.77E-04
Naphthalene	3.00E-04	1.93E-06	1.7E-02	8.43E-06
PAHs (excluding naphthalene)	1.00E-04	6.42E-07	5.6E-03	2.81E-06
Propylene oxide	n/a	--	--	--
Toluene	3.66E-02	2.35E-04	2.1	1.03E-03
Xylene	2.72E-02	1.75E-04	1.5	7.65E-04
Total HAPs			6.3	3.15E-03

Notes:
(1) All factors from Ventura County APCD, "AB2588 Combustion Emission Factors," Natural Gas Fired External Combustion Equipment <10 MMBtu/hr. Available at http://www.vcapcd.org/pubs/Engineering/AirToxics/combem.pdf
(2) Based on maximum hourly heat input of 6418 scf/hr
(3) Based on total annual fuel use of 56.2 MMscf/yr

Appendix B

Modeling Parameters

Table B-1
Gateway Generating Station
Building Dimensions Used for Modeling

Structure	Dimensions (meters)		
	Height	**Length (y)**	**Width (x)**
Onsite Structures			
Combustion Turbines (each)	17.4	10.0	79.0
HRSGs (each)	28.0	10.0	24.0
Air-Cooled Condenser	39.0	86.0	76.0
Wet Surface Air Cooler	5.8	4.0	17.0
Dewpoint Heater	1.8	8.0	1.0
Firepump Engine Encl.	3.3	21.0	12.0
Tank 88	5.2	15.0	
Tank 89	5.2	10.0	
Tank 144	6.4	9.0	
Tank 149	5.2	7.0	
Offsite Structures			
Units 6&7	44.7	35.0	94.0
Steam Turbine Bldg	20.6	44.0	113.0
Units 1-3	42.1	46.0	60.0
Units 4&5	20.6	26.0	87.0
Tanks 1-5	22.0	43.0	
Tanks 6-8	29.3	98.0	

Table B-2
Gateway Generating Station
Emissions and Stack Parameters for Screening Modeling

Turbine Case Number	Turbine Case Condition	Ambient Temp	Load	Stack Diam (m)	Stack Ht (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)	NOx, g/s per turbine	SO2, g/s per turbine	CO, g/s per turbine	PM10, g/s per turbine
1	Cold Base	30.0	100%	5.11	59.436	355.222	21.369	1.688	6.578E-01	2.056	1.386
2	Cold Low	30.0	50%	5.11	59.436	355.222	13.979	1.104	4.303E-01	1.345	1.386
3	Avg. Base	60.0	100%	5.11	59.436	355.222	21.567	1.688	6.578E-01	2.056	1.386
4	Avg. Low	60.0	50%	5.11	59.436	355.222	14.844	1.162	4.527E-01	1.415	1.386
5	Avg. Peak	60.0	100%	5.11	59.436	355.222	19.923	1.913	7.455E-01	2.330	1.512
6	Hot Base	100.0	100%	5.11	59.436	355.222	22.120	1.688	6.578E-01	2.056	1.386
7	Hot Low	100.0	50%	5.11	59.436	355.222	13.334	1.018	3.965E-01	1.239	1.386
8	Hot Peak	100.0	100%	5.11	59.436	355.222	20.429	1.913	7.455E-01	2.330	1.512

Table B-3
Gateway Generating Station
Results of the CTG Screening Analysis

Case	Max. Impact, ug/m3 per 1.0 g/s				
	1-hr	3-hr	8-hr	24-hr	annual
	2004 Met Data				
1	10.698	6.188	2.996	1.022	0.145
2	13.185	6.859	3.989	1.454	0.211
3	10.646	6.163	2.973	1.014	0.144
4	12.533	6.732	3.833	1.363	0.200
5	11.048	6.364	3.154	1.077	0.155
6	10.494	6.092	2.913	0.994	0.141
7	13.609	6.979	4.112	1.527	0.219
8	10.933	6.304	3.096	1.057	0.152
	2005 Met Data				
1	12.629	4.762	2.076	1.249	0.167
2	14.740	6.646	3.074	1.902	0.241
3	12.599	4.723	2.055	1.239	0.165
4	14.171	6.357	2.922	1.803	0.229
5	12.774	5.062	2.231	1.330	0.178
6	12.504	4.617	2.001	1.214	0.161
7	15.136	6.874	3.195	1.980	0.250
8	12.737	4.952	2.175	1.299	0.174
	2006 Met Data				
1	11.574	5.657	3.217	1.291	0.157
2	14.091	7.289	3.811	1.887	0.225
3	11.506	5.650	3.197	1.283	0.156
4	13.583	7.050	3.694	1.780	0.215
5	12.063	5.809	3.355	1.356	0.168
6	11.314	5.629	3.142	1.261	0.152
7	14.465	7.449	3.912	1.965	0.234
8	11.884	5.697	3.307	1.332	0.164

Table B-3 (cont'd)

Turbine Case	Emission Rates for Screening Modeling (lb/hr)									
	NOx		SO2				CO		PM10	
	1-hr	annual avg	1-hr	3-hr	24-hr	annual avg	1-hr	8-hr	24-hr	annual avg
1	14.11	19.69	5.498	5.498	5.498	4.31	17.18	17.18	11.0	11.59
2	7.93	19.69	3.089	3.089	3.089	4.31	9.65	9.65	11.0	11.59
3	13.40	19.69	5.221	5.221	5.221	4.31	16.31	16.31	11.0	11.59
4	9.22	19.69	3.593	3.593	3.593	4.31	11.23	11.23	11.0	11.59
5	15.18	19.69	5.917	5.917	5.917	4.31	18.49	18.49	12.0	11.59
6	13.40	19.69	5.221	5.221	5.221	4.31	16.31	16.31	11.0	11.59
7	8.39	19.69	3.269	3.269	3.269	4.31	10.21	10.21	11.0	11.59
8	15.18	19.69	5.917	5.917	5.917	4.31	18.49	18.49	12.0	11.59

Turbine Case	Turbine Emission Rates for Screening Modeling (g/s)									
	NOx		SO2				CO		PM10	
	1-hr	annual avg	1-hr	3-hr	24-hr	annual avg	1-hr	8-hr	24-hr	annual avg
1	1.778	2.481	0.693	0.693	0.693	0.543	2.165	2.165	1.386	1.460
2	0.999	2.481	0.389	0.389	0.389	0.543	1.216	1.216	1.386	1.460
3	1.688	2.481	0.658	0.658	0.658	0.543	2.056	2.056	1.386	1.460
4	1.162	2.481	0.453	0.453	0.453	0.543	1.415	1.415	1.386	1.460
5	1.913	2.481	0.745	0.745	0.745	0.543	2.330	2.330	1.512	1.460
6	1.688	2.481	0.658	0.658	0.658	0.543	2.056	2.056	1.386	1.460
7	1.057	2.481	0.412	0.412	0.412	0.543	1.287	1.287	1.386	1.460
8	1.913	2.481	0.745	0.745	0.745	0.543	2.330	2.330	1.512	1.460

Turbine Case	Load/ Ambient Temp	Modeled Impacts, ug/m3, by Pollutant and Averaging Period									
		NOx		SO2				CO		PM10	
		1-hr	Annual	1-hr	3-hr	24-hr	Annual	1-hr	8-hr	24-hr	Annual
1	Cold Base	22.450	0.414	8.7482	4.287	0.8947	0.0906	27.338	6.963	1.79	0.244
2	Cold Low	14.721	n/a	5.7364	2.837	0.7400	n/a	17.926	4.852	2.64	n/a
3	Avg. Base	21.268	0.411	8.2876	4.054	0.8441	0.0898	25.898	6.572	1.78	0.242
4	Avg. Low	16.465	n/a	6.4159	3.192	0.8162	n/a	20.049	5.423	2.50	n/a
5	Avg. Peak	**24.437**	**0.442**	**9.5226**	**4.744**	**1.0111**	**0.0967**	**29.757**	**7.815**	2.05	**0.260**
6	Hot Base	21.108	0.401	8.2252	4.007	0.8293	0.0876	25.703	6.460	1.75	0.236
7	Hot Low	15.998	n/a	6.2340	3.068	0.8153	n/a	19.481	5.292	**2.74**	n/a
8	Hot Peak	24.367	0.432	9.4953	4.700	0.9932	0.0945	29.672	7.705	2.01	0.254

Table B-4
Gateway Generating Station
Emission Rates and Stack Parameters for Refined Modeling

	Stack Diam, m	Release Height m	Temp, deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Emission Rates, g/s			
						NOx	SO2	CO	PM10
Averaging Period: One hour									
Gas Turbine 1	5.108	59.436	355.37	408.350	19.923	1.9131	0.7455	2.3296	n/a
Gas Turbine 2	5.108	59.436	355.37	408.350	19.923	1.9131	0.7455	2.3296	n/a
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	0.0494	2.310E-03	2.408E-02	n/a
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	0.3633	3.704E-04	2.667E-02	n/a
Averaging Period: Three hours SOx									
Gas Turbine 1	5.108	59.436	355.37	408.350	19.923	n/a	0.7455	n/a	n/a
Gas Turbine 2	5.108	59.436	355.37	408.350	19.923	n/a	0.7455	n/a	n/a
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	n/a	2.310E-03	n/a	n/a
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	n/a	1.235E-04	n/a	n/a
Averaging Period: Eight hours CO									
Gas Turbine 1	5.108	59.436	355.37	408.350	19.923	n/a	n/a	85.6324	n/a
Gas Turbine 2	5.108	59.436	355.37	408.350	19.923	n/a	n/a	85.6324	n/a
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	n/a	n/a	2.408E-02	n/a
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	n/a	n/a	3.333E-03	n/a
Averaging Period: 24-hour SOx									
Gas Turbine 1	5.108	59.436	355.37	408.350	19.923	n/a	0.7455	n/a	n/a
Gas Turbine 2	5.108	59.436	355.37	408.350	19.923	n/a	0.7455	n/a	n/a
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	n/a	2.310E-03	n/a	n/a
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	n/a	1.544E-05	n/a	n/a
Averaging Period: 24-hour PM10									
Gas Turbine 1	5.108	59.436	355.37	273.286	13.334	n/a	n/a	n/a	1.3860
Gas Turbine 2	5.108	59.436	355.37	273.286	13.334	n/a	n/a	n/a	1.3860
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	n/a	n/a	n/a	6.044E-03
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	n/a	n/a	n/a	4.167E-04
WSAC (each, eight cells)	1.651	5.823	308.15	28.317	13.227	n/a	n/a	n/a	3.058E-03
Averaging Period: Annual									
Gas Turbine 1	5.108	59.436	355.37	408.350	19.923	2.4813	0.5316	n/a	1.4594
Gas Turbine 2	5.108	59.436	355.37	408.350	19.923	2.4813	0.5316	n/a	1.4594
Dewpoint Heater	0.203	4.715	422.04	0.927	28.719	4.939E-02	1.733E-03	n/a	6.044E-03
Fire Pump Engine	0.154	3.251	683.15	0.821	44.058	2.074E-03	2.114E-06	n/a	5.708E-05
WSAC (each, eight cells)	1.651	5.823	308.15	28.317	13.227	n/a	n/a	n/a	3.058E-03

Table B-5
Gateway Generating Station
Calculation of Inversion Fumigation Impacts

CTG Emission Rates, g/s per train

Case	NOx	SO2	CO	PM10
1	1.688	0.658	2.056	1.386
2	1.104	0.430	1.345	1.386
3	1.688	0.658	2.056	1.386
4	1.162	0.453	1.415	1.386
5	1.913	0.745	2.330	1.512
6	1.688	0.658	2.056	1.386
7	1.018	0.397	1.239	1.386
8	1.913	0.745	2.330	1.512

Inversion Breakup Modeling Results from SCREEN3

Case	Unit Impacts, ug/m3 per g/s	Maximum One-Hour Avg Impacts, ug/m3, 2 trains				Distance to Maximum (m)
		NOx	SO2	CO	PM10	
1	1.035	3.4944	1.3617	4.2552	2.8690	18,291
2	1.32	2.9155	1.1361	3.5503	18.2952	15,269
3	1.132	3.8219	1.4893	4.6540	15.6895	17,107
4	1.402	3.2578	1.2695	3.9671	19.4317	14,592
5	1.185	4.5341	1.7668	5.5212	17.9172	16,538
6	1.348	4.5512	1.7735	5.5420	18.6833	15,032
7	1.816	3.6959	1.4402	4.5005	25.1698	12,034
8	1.413	5.4065	2.1068	6.5835	21.3646	14,507

Flat Terrain Modeling Results from SCREEN3

Case	Unit Impacts, ug/m3 per g/s	Maximum One-Hour Avg Impacts, ug/m3, 2 trains				Distance to Maximum (m)
		NOx	SO2	CO	PM10	
1	0.9819	3.3151	1.2918	4.0369	2.7218	1,074
2	1.316	2.9067	1.1327	3.5395	3.6480	1,085
3	1.089	3.6767	1.4327	4.4772	3.0187	1,149
4	1.521	3.5344	1.3772	4.3038	4.2162	1,038
5	1.17	4.4767	1.7444	5.4513	3.5381	1,124
6	1.532	5.1724	2.0156	6.2985	4.2467	1,035
7	2.068	4.2088	1.6400	5.1250	5.7325	949
8	1.642	6.2827	2.4482	7.6504	4.9654	1,014

Adjust unit impacts for longer averaging periods to account for 90-minute duration of fumigation

Case	1-hr unit	3-hr unit	8-hr unit	24-hr unit
1	1.035	1.008	0.992	0.985
2	1.320	1.318	1.317	1.316
3	1.132	1.111	1.097	1.092
4	1.521	1.521	1.521	1.521
5	1.185	1.178	1.173	1.171
6	1.532	1.532	1.532	1.532
7	2.068	2.068	2.068	2.068
8	1.642	1.642	1.642	1.642

Table B-5 (cont'd)

Calculation of Fumigation Impacts

Case/Avg Period	NOx	SO2	CO	PM10
One-Hour				
1	3.4944	1.3617	4.2552	-
2	2.9155	1.1361	3.5503	-
3	3.8219	1.4893	4.6540	-
4	3.5344	1.3772	4.3038	-
5	4.5341	1.7668	5.5212	-
6	5.1724	2.0156	6.2985	-
7	4.2088	1.6400	5.1250	-
8	**6.2827**	**2.4482**	**7.6504**	-
3 Hours				
1	-	1.1941	-	-
2	-	1.0209	-	-
3	-	1.3149	-	-
4	-	1.2395	-	-
5	-	1.5801	-	-
6	-	1.8140	-	-
7	-	1.4760	-	-
8	-	**2.2034**	-	-
8 Hours				
1	-	-	2.8545	-
2	-	-	2.4791	-
3	-	-	3.1572	-
4	-	-	3.0127	-
5	-	-	3.8251	-
6	-	-	4.4089	-
7	-	-	3.5875	-
8	-	-	**5.3553**	-
24 Hours				
1	-	0.5185	-	1.0924
2	-	0.4532	-	1.4595
3	-	0.5745	-	1.2105
4	-	0.5509	-	1.6865
5	-	0.6983	-	1.4164
6	-	0.8062	-	1.6987
7	-	0.6560	-	**2.2930**
8	-	**0.9793**	-	1.9862

Table B-6
Gateway Generating Station
Calculation of Shoreline Fumigation Impacts

Emission Rates, g/s per CTG

Case	NOx	SO2	CO	PM10
1	1.688	0.658	2.056	1.386
2	1.104	0.430	1.345	1.386
3	1.688	0.658	2.056	1.386
4	1.162	0.453	1.415	1.386
5	1.913	0.745	2.330	1.512
6	1.688	0.658	2.056	1.386
7	1.018	0.397	1.239	1.386
8	1.913	0.745	2.330	1.512

Shoreline Fumigation Breakup Modeling Results from SCREEN3

	Unit Impacts, ug/m3 per g/s					Distance to Maximum (m)
Case	TIBL 2	TIBL 3	TIBL 4	TIBL 5	TIBL 6	
1	0.713	1.941	3.670	5.558	7.334	1,553
2	0.897	2.541	4.876	7.429	9.756	1,188
3	0.776	2.144	4.075	6.184	8.148	1,409
4	0.948	2.710	5.220	7.978	10.450	1,111
5	0.811	2.255	4.298	6.528	8.595	1,340
6	0.915	2.601	4.998	7.624	10.000	1,159
7	1.183	3.559	6.956	10.710	13.890	833
8	0.954	2.732	5.265	8.049	10.540	1,102

Highest Shoreline Fumigation Breakup Modeling Results (TIBL = 6)

		Maximum One-Hour Avg Impacts, ug/m3, 2 trains				
Case	Impacts, ug/m3 per g/s	NO2	SO2	CO	PM10	Distance to Maximum (m)
1	7.334	24.76	9.65	30.15	20.33	1,647
2	9.76	21.55	8.40	26.24	27.04	1,144
3	8.148	27.51	10.72	33.50	22.59	1,409
4	10.45	24.28	9.46	29.57	28.97	1,111
5	8.595	32.89	12.81	40.05	25.99	1,340
6	10.00	33.76	13.16	41.11	27.72	1,159
7	13.89	28.27	11.02	34.42	38.50	855
8	10.54	40.33	15.71	49.11	31.87	1,102

Table B-6 (cont'd)

Flat Terrain Modeling Results from SCREEN3

Case	Impacts, ug/m3 per g/s	Maximum One-Hour Avg Impacts, ug/m3, 2 trains				Distance to Maximum (m)
		NOx	SO2	CO	PM10	
1	0.9754	3.2932	1.2833	4.0101	2.7038	1,075
2	1.242	2.7433	1.0690	3.3405	3.4428	1,104
3	1.089	3.6767	1.4327	4.4772	3.0187	1,149
4	1.521	3.5344	1.3772	4.3038	4.2162	1,038
5	1.17	4.4767	1.7444	5.4513	3.5381	1,124
6	1.532	5.1724	2.0156	6.2985	4.2467	1,035
7	2.068	4.2088	1.6400	5.1250	5.7325	949
8	1.642	6.2827	2.4482	7.6504	4.9654	1,014

Adjust unit impacts for longer averaging periods to account for 180-minute duration of fumigation (ug/m3 per g/s)

Case	1-hr unit	3-hr unit	8-hr unit	24-hr unit
1	7.334	7.334	3.360	1.770
2	9.76	9.76	4.435	2.306
3	8.148	8.148	3.736	1.971
4	10.45	10.45	4.869	2.637
5	8.595	8.595	3.954	2.098
6	10.00	10.00	4.708	2.591
7	13.89	13.89	6.501	3.546
8	10.54	10.54	4.979	2.754

Table B-6 (cont'd)

Calculation of Shoreline Fumigation Impacts

Case/Avg Period	NO2	SO2	CO	PM10
One-Hour				
1	24.76	9.65	30.15	-
2	21.55	8.40	26.24	-
3	27.51	10.72	33.50	-
4	24.28	9.46	29.57	-
5	32.89	12.81	40.05	-
6	33.76	13.16	41.11	-
7	28.27	11.02	34.42	-
8	**40.33**	**15.71**	**49.11**	-
3 Hours				
1	-	8.68	-	-
2	-	7.56	-	-
3	-	9.65	-	-
4	-	8.52	-	-
5	-	11.53	-	-
6	-	11.84	-	-
7	-	9.91	-	-
8	-	**14.14**	-	-
8 Hours				
1	-	-	9.67	-
2	-	-	8.35	-
3	-	-	10.75	-
4	-	-	9.64	-
5	-	-	12.90	-
6	-	-	13.55	-
7	-	-	11.28	-
8	-	-	**16.24**	-
24 Hours				
1	-	0.93	-	1.96
2	-	0.79	-	2.56
3	-	1.04	-	2.19
4	-	0.96	-	2.92
5	-	1.25	-	2.54
6	-	1.36	-	2.87
7	-	1.12	-	**3.93**
8	-	**1.64**	-	3.33

Table B-7
Gateway Generating Station
Emission Rates and Stack Parameters for Modeling Startup Impacts
One CTG in startup, per Condition 22

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Em Rates, g/s	
						NOx	CO
One unit in startup	5.108	59.436	355.222	273.286	13.334	20.16	113.40
One unit in operation (Case 5)	5.108	59.436	355.222	408.350	19.923	1.91	2.33
Dewpoint Heater	0.203	4.715	421.889	0.927	28.719	0.05	0.02

Table B-8
Gateway Generating Station
Emission Rates and Stack Parameters for Modeling Commissioning Impacts

	Stack Diam, m	Stack Height, m	Exh Temp, Deg K	Exhaust Flow, m3/s	Exhaust Velocity, m/s	Em Rates, g/s	
						NOx	CO
Gas Turbine 1	5.108	59.436	355.222	273.286	13.334	25.20	252.00
Gas Turbine 2	5.108	59.436	355.222	273.286	13.334	25.20	252.00

Max. Modeled Impact During Commissioning of Two CTGs

	Max Modeled Conc, ug/m3	Background, ug/m3	Total Impact, ug/m3	State Standard, ug/m3	Federal Standard, ug/m3
NO2, 1 hr ozone lmtd	152	109	261	338	--
CO, 1 hr	4,065	5,125	9,190	23,000	40,000
CO, 8 hr	1,042	2,133	3,175	10,000	10,000

Attachment B-1

Modeling Protocol and BAAQMD Comments

sierra research

Gateway Generating Station Modeling Protocol

prepared for:

Pacific Gas & Electric Company

August 2007

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Gateway Generating Station
Modeling Protocol

August 2007

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Gateway Generating Station
Modeling Protocol

Table of Contents

1. Background 1

2. Project Location 2

3. Emission Sources 3

4. Meteorological Data 3

5. Site Representation – Meteorological Data 3

6. Existing Ambient Air Quality Data 4

7. Air Quality Dispersion Models 4

8. Good Engineering Practice (GEP) Stack Height and Downwash 6

9. Receptor Selection 6

10. Modeling Scenarios 7

11. Class I Area Impact Methodology 8

12. Screening Health Risk Analysis 8

13. Final Modeling Submittal 9

14. References 11

Appendix A – Surface Parameters to be used in AERMET Stage 3 Processing

Appendix B – Information on CTDMPLUS Model

Gateway Generating Station
Modeling Protocol
August 2007

1. Background

On behalf of Pacific Gas & Electric Company (PG&E), Sierra Research is submitting this modeling protocol to the Bay Area Air Quality Management District (BAAQMD or District) and California Energy Commission (CEC) for approval of the air dispersion and health risk assessment modeling proposed to be conducted in support of modifications to the Gateway Generating Station (GGS or Project) BAAQMD Authority to Construct and the CEC Conditions of Certification. GGS was permitted by the BAAQMD and licensed by the CEC in 2001 as Contra Costa Power Project Unit 8 (CC8), which was then owned by Mirant Delta LLC. Mirant commenced construction of the facility in late 2001, but suspended construction activities in February 2002. Ownership of the project was transferred to PG&E in November 2006, and construction recommenced in early February 2007. The BAAQMD renewed the Authority to Construct in June 2007. In August 2007, the CEC approved several changes to the project that did not require changes to the BAAQMD Authority to Construct; the most notable air quality-related change was the replacement of the original wet cooling tower with an air-cooled condenser and small wet surface-air cooler.

PG&E has reviewed the permit conditions and emission limits in the Authority to Construct and the Conditions of Certification and has determined that several changes to the physical design of the facility and to several of the operating assumptions are needed to allow the facility to operate effectively and efficiently. In the application to be filed with the District and the CEC, PG&E will propose the following changes to the permitted facility:

- Eliminate the 10-cell wet cooling tower and replace it with a dry cooling system, including an exempt wet surface air cooler;[1]
- Replace the permitted natural gas-fired dew point gas heater with a smaller unit and increase allowable daily hours of operation;
- Change the allowable emission limits for the gas turbines during startup operations;

[1] As indicated above, this amendment has already been approved by the CEC. However, since the installation of the dry cooling system did not require a change to the BAAQMD ATC, the BAAQMD permit does not yet include this project modification.

- Reduce the permitted hourly emission rates for NOx and PM_{10} and increase the allowable ammonia slip limit, based on current BACT and on operating experience from other 7FA gas turbine facilities;
- Reduce the annual average allowable sulfur content of the natural gas;
- Reduce the permitted hourly emission rates and increase the annual emission limit for CO, based on current BACT and operating experience from other 7FA gas turbine facilities;
- Change the allowable emission rates for the gas turbines and HRSGs during commissioning activities, based on recent project experience; and
- Replace the electric motor-driven fire water pump with a 300 kW Diesel fire pump engine.

Annual emission limits of all pollutants except CO will be reduced or will stay the same as the limits in the existing ATC and conditions of certification. The proposed increase in annual CO emissions will exceed 100 tons per year, so the Project will be a major modification of the existing major source under District New Source Review regulations.

PG&E is also proposing to increase allowable short-term emissions of NOx and CO from the CTGs/HRSGs during startups and commissioning operations. No increases in short-term or annual SO_2 or PM_{10} emissions will result from the proposed permit modifications.

Impacts from operation of the facility will be compared to the following thresholds:

Air Quality Criteria	**NO_2**	**CO**
PSD Significant Impact Levels	n/a[a,b]	√
BAAQMD Significant Impact Levels	n/a[a]	√
PSD Monitoring Exemption Levels	n/a[a]	√
Ambient Air Quality Standards (AAQS)	√[c]	√

Notes:
a. PSD significant impact and monitoring exemption levels apply only if the project is subject to PSD review. Because the project will not result in an increase in permitted annual NOx emissions, the project is not subject to PSD review for NO_2.
b. n/a: Not applicable.
c. State one-hour average NO_2 standard only.

2. Project Location

The project is located at 3225 Wilbur Avenue, Antioch. The location of the site is approximately 4208.2 km N, 609.0 km E. The nominal site elevation is 2 meters (6.6 feet) above mean sea level.

3. EMISSION SOURCES

GGS is a 530-megawatt (MW) nominal combined cycle electric generation facility. Permitted equipment at GGS consists of two GE 7FA natural gas-fired combustion turbines with supplemental duct fired heat recovery steam generators (S-41, S-42, S-43 and S-44), a natural gas fired dew point gas heater (S-45), a 10-cell cooling tower (S-46) and an oil-water separator (S-48). The proposed equipment changes and their potential emissions and air quality impacts are listed below.

- Replace the 10-cell cooling tower (S-46) with air-cooled condenser and small wet surface-air cooler, both exempt from permitting, reducing PM_{10} emissions;
- Replace the natural gas-fired dew point gas heater (S-45) with a smaller unit and increase allowable daily operation, reducing hourly NOx emissions (no increase in annual NOx emissions); and
- Add a new Diesel fire pump engine, adding a source of Diesel particulate matter (a toxic air contaminant).

4. METEOROLOGICAL DATA

The ambient air quality analysis will use four years of meteorological data (1994 through 1997) collected at the existing Contra Costa Power Plant less than one-half of a mile from the proposed project site. Upper air data will be taken from Oakland. The BAAQMD's standard maximum mixing height of 600 meters will be used. The meteorological data processor AERMET will be used to generate AERMOD-compatible meteorological data for air dispersion modeling.

5. SITE REPRESENTATION – METEOROLOGICAL DATA

USEPA defines the term "site specific data" to mean data that would be representative of atmospheric dispersion conditions at the source and at locations where the source may have a significant impact on air quality. Specifically, the meteorological data requirement originates in the Clean Air Act at Section 165(e)(1), which requires an analysis "of the ambient air quality at the proposed site and in areas which may be affected by emissions from such facility for each pollutant subject to regulation under [the Act] which will be emitted from such facility."

This requirement and USEPA's guidance on the use of on-site monitoring data are also outlined in the "*Meteorological Monitoring Guidance for Regulatory Modeling Applications*" (2000). The representativeness of the data depends on (a) the proximity of the meteorological monitoring site to the area under consideration, (b) the complexity of the topography of the area, (c) the exposure of the meteorological sensors, and (d) the period of time during which the data are collected. The meteorological data collected at the Contra Costa Power Plant have previously been accepted by the BAAQMD and CEC staffs as representative of conditions at the project site.[2]

6. Existing Ambient Air Quality Data

Background ambient air quality data for the project area during 2004-2006 will be obtained from the monitoring site nearest to the project site. The Pittsburg 10th Street monitoring site is the nearest with background data for CO and NO_2. Modeled concentrations will be added to these representative background concentrations to determine compliance with the CAAQS and NAAQS.

7. Air Quality Dispersion Models

Overview

The following USEPA air dispersion models are proposed for use to quantify pollutant impacts on the surrounding environment based on the emission sources' operating parameters and their locations:

- American Meteorological Society/Environmental Protection Agency Regulatory Model Improvement Committee (AERMIC) model, also known as AERMOD (Version 07026);
- Building Profile Input Program – Plume Rise Model Enhancements (BPIP-PRIME, current version 04274); and
- SCREEN3 (Version 96043).

The following models are not expected to be used, but they are listed in the event that an optional specialized modeling analysis is necessary for the project.

- Complex Terrain SCREEN (CTSCREEN, Version 94111); and
- Complex Terrain Dispersion Model (CTDMPLUS, Version 93228).

The three primary models listed above, and how they are used, are discussed below. Further information on the use of CTDMPLUS and CTSCREEN is provided in Appendix B.

Simple, Complex, and Intermediate Terrain Impacts

For modeling project emissions in simple, complex, and intermediate terrain, the USEPA-recommended guideline model AERMOD will be used with the AERMET-processed hourly meteorological data from the Contra Costa Power Plant monitoring station during 1994-1997. The AERMOD model requires hourly

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[2] BAAQMD, Final Determination of Compliance, Contra Costa Power Plant Unit 8 Project, February 2, 2001; and CEC Final Staff Assessment for Contra Costa Power Plant Unit 8 Project (00-AFC-1), March 2001.

meteorological data consisting of wind vector and speed (with reference height), temperature (with reference height), Monin-Obukhov length, surface roughness length, heights of the mechanically- and convectively-generated boundary layers, surface friction velocity, convective velocity scale, and vertical potential temperature gradient in the 500-meter layer above the planetary boundary layer. The model assumes that there is no variability in meteorological parameters over a one-hour time period, hence the term "steady-state." The AERMOD model allows input of multiple sources and source groupings, eliminating the need for multiple model runs. Complex phenomena such as building-induced plume downwash are treated in this model. The parameters we propose to use in the AERMET Stage 3 processing to characterize surface conditions are shown in detail in Appendix A.

Standard AERMOD control parameters will be used (stack tip downwash, non-screening mode, non-flat terrain, sequential meteorological data check employed). Stack-tip downwash, which adjusts the effective stack height downward following the methods of Briggs (1972) for cases where the stack exit velocity is less than 1.5 times the wind speed at stack top, will be selected per USEPA and BAAQMD guidance. Other options that will be used in accordance with BAAQMD guidance include gradual plume rise and buoyancy-induced dispersion. As for the original modeling analysis for this facility, the rural default option will be used.[3]

Ozone Limiting Method

For evaluating compliance with the state one-hour average NO_2 standard, the tiered screening approach as described in "Supplement C To The Guideline On Air Quality Models (Revised)," EPA, August 1995 (EPA-450/2-78-027R-C) will be used. The initial assumption will be that all of the NOx converts to NO_2. If maximum hourly NO_2 concentrations need to be examined in more detail, the Plume Volume Molar Ratio Method (PVMRM) adaptation of the Ozone Limiting Method (Cole and Summerhays, 1979) will be used. AERMOD PVMRM will be used to calculate the NO_2 concentration based on the PVMRM method and hourly ozone data. Hourly ozone data collected at the Pittsburg 10th Street monitoring station during the years 1994-1997 will be used in conjunction with PVMRM to calculate hourly NO_2 concentrations from hourly NOx concentrations. Missing hourly ozone data will be substituted prior to use with day-appropriate values (e.g., from the previous day, or the next day, for the same hour). Any other missing hourly ozone data will be substituted with 40 ppb ozone (typical ozone tropospheric background level). The PVMRM involves an initial comparison of the estimated maximum NOx concentration and the ambient O_3 concentration in the plume after dilution to determine whether NO or O_3 is the limiting factor to NO_2 formation. If the O_3 concentration is greater than the maximum

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[3] The rural vs. urban option in AERMOD is primarily designed to set the fraction of incident heat flux that is transferred into the atmosphere. This fraction becomes important in urban areas having an appreciable "urban heat island" effect due to a large presence of land covered by concrete, asphalt, and buildings. This situation does not exist for the proposed project site.

NOx concentration, total conversion is assumed. If the NOx concentration is greater than the remaining O_3 concentration, the formation of NO_2 is limited by the remaining ambient O_3 concentration. In this case, the NO_2 concentration is set equal to the O_3 concentration plus a correction factor that accounts for in-stack and near-stack thermal conversion.

Fumigation

The SCREEN3 model will be used to evaluate inversion breakup and shoreline fumigation impacts for short-term averaging periods (24 hours or less), as appropriate. The methodology in USEPA, 1992 (Screening Procedures for Estimating the Air Quality Impact of Stationary Sources, Revised) and BAAQMD guidance (*http://www.baaqmd.gov/pmt/air_toxics/permit_ modeling/pmt_modeling_guidance.pdf*) will be followed for these analyses. Combined impacts for all sources under fumigation conditions will be evaluated, based on USEPA and applicable BAAQMD modeling guidelines.

8. GOOD ENGINEERING PRACTICE (GEP) STACK HEIGHT AND DOWNWASH

AERMOD can account for building downwash effects on dispersing plumes. Stack locations and heights and building locations and dimensions will be input to BPIP-PRIME. The first part of BPIP-PRIME determines and reports on whether a stack is being subjected to wake effects from a structure or structures. The second part calculates direction-specific building dimensions for each structure that are used by AERMOD to evaluate wake effects. The BPIP-PRIME output is formatted for use in AERMOD input files.

9. RECEPTOR SELECTION

Receptor and source base elevations will be determined from USGS Digital Elevation Model (DEM) data using the 7½-minute format (10- to 30-meter spacing between grid nodes). All coordinates will be referenced to UTM North American Datum 1927 (NAD27), Zone 11. The AERMOD receptor elevations will be interpolated among the DEM nodes according to standard AERMAP procedure. For determining concentrations in elevated terrain, the AERMAP terrain preprocessor receptor-output (ROU) file option will be chosen; hills will not be imported into AERMOD for CTDM-like processing.

Cartesian coordinate receptor grids will be used to provide adequate spatial coverage surrounding the project area for assessing ground-level pollution concentrations, to identify the extent of significant impacts, and to identify maximum impact locations. A 250-meter resolution coarse receptor grid will be developed and will extend outwards at least 10 km (or more as necessary to calculate the significant impact area).

For the full impact analyses, a nested grid will be developed to fully represent the maximum impact area(s). This grid will have 25-meter resolution along the facility fence-line in a single tier of receptors composed of four segments extending out to 100 meters from the fenceline, 100-meter resolution from 100 meters to 1,000 meters from the fenceline, and 250-meter spacing out to at least 10 km from the site. When maximum first-high or maximum second-high impacts occur in the 250-meter spaced area, additional refined receptor grids with 25-meter resolution will be placed around the maximum coarse grid impacts and extended out 1,000 meters in all directions. Concentrations within the facility fenceline will not be calculated.

10. MODELING SCENARIOS

The only changes proposed for the emissions limitations affect short-term emission limits and/or short-term standards. Therefore, the following scenarios will be modeled:

- 1-hr and 8-hr average CO during turbine startup/shutdown and turbine commissioning; and
- 1-hr average NO_2 during turbine startup/shutdown and turbine commissioning.

In the modeling analysis, startup conditions will be represented by minimum load (50% load) stack parameters and proposed permitted emission rates.

Details of Operating Scenarios

The following table gives more detail on the operating modes to be modeled.

Operating Modes of the Combustion Gas Turbines	
Mode	Description
Commissioning	The process of fine-tuning each of the turbines. The facility will follow a systematic approach to optimize performance of the turbines and the associated control equipment. Emissions are expected to be greater during commissioning than during normal operation for NOx, CO, and POC. This one-time mode affects only the initial year of operation.
Startup/Shutdown	Startup NOx and CO emissions are higher because low-NOx combustors are not able to operate in their optimal mode, and the SCR and oxidation catalysts have not reached optimal temperature to begin the chemical reactions needed to reduce NOx and oxidize CO in the turbine/HRSG exhaust. Shutdown occurs at the initiation of the turbine shutdown sequence and ends with the cessation of turbine firing. Typically, the shutdown process will have lower emissions than the startup process so will not be modeled separately.

Ambient Air Quality Impact Analyses

In evaluating the impacts of the proposed project on ambient air quality, we will model the ambient impacts of the project, add those impacts to background concentrations, and compare the results to the state and federal ambient standards for NO_2 and CO.

11. Class I Area Impact Methodology

No changes are being proposed that would affect annual emissions of pollutants that interfere with visibility or produce acid deposition (NO_2, SO_2 or PM_{10}), and hence, no significant impacts are expected on Class I areas.

12. Screening Health Risk Analysis

District Regulation 2, Rule 5 requires preconstruction review for potential health impacts from new and modified sources of toxic air contaminants. Toxic emissions are estimated for all sources within a proposed project; if emissions from a proposed project exceed the BAAQMD regulatory trigger levels, a Health Risk Screening Analysis (HRSA) is required to determine project risk and risk from each source. A HRSA was prepared for the original permitting and licensing of the CC8 project. This HRSA will be updated to reflect the proposed 10 ppm ammonia slip level, the proposed new Diesel emergency fire pump engine, and the most current risk values published by OEHHA. The HRA modeling will be prepared using ARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.3, October 18, 2005). The HARP model will be used to assess cancer risk as well as non-cancer chronic and acute health hazards. The HRA will include the four following pathways: inhalation, dermal absorption, soil and mother's milk ingestion.

Because the HARP model incorporates the previously USEPA-approved model ISCST3, a special methodology will be employed to be consistent with using AERMOD for the air dispersion modeling and retain the health values and risk computations provided by HARP Version 1.3. The OEHHA/ARB-approved methodology used to prepare the HRA has been described by the ARB[4] and is described below. Its use has also been accepted by both the CEC and the District for previous power plant projects.

<u>Modeling Inputs</u> – The risk assessment module of the HARP model is run using unit ground level impacts to obtain derived cancer risks for each toxic air contaminant (TAC). The HARP model output is cancer risk by TAC and pathway for each type of analysis, based on an exposure of 1.0 $\mu g/m^3$. Individual cancer risks are expressed in units of risk per $\mu g/m^3$ of exposure. To calculate the weighted risk for each source, the annual average emission rate in grams per second for each TAC will be multiplied by the individual cancer risk for that TAC in units of $(\mu g/m^3)^{-1}$. The resulting weighted cancer risks for each TAC will then be summed for the source. The same approach will be used to determine the non-cancer acute and chronic health hazards associated with the Project.

Health risk from exposure to a carcinogenic TAC is calculated as the product of the exposure concentration times a factor representing the risk per unit concentration (i.e., unit risk) for the TAC. In the case of cancer risk, the risk per unit concentration depends on breathing rate, the cancer potency factor of the TAC, dimensional factors, and other

[4] ARB. Part B of Topic 8 of the HARP How-To Guides: How to Perform Health Analyses Using a Ground Level Concentration.

terms involving non-inhalation pathways, when relevant. In the case of chronic and acute non-cancer impacts, the unit impact or health hazard per unit concentration is normally calculated as 1 divided by the Reference Exposure Level (REL, expressed as a concentration in $\mu g/m^3$) for the TAC.

Exposure concentration is calculated as the product of the actual emission rate (in grams per second) of the TAC times the concentration per unit of emission (i.e., an emission rate of 1 g/s), which is the output from the AERMOD air dispersion modeling calculation. This exposure concentration is the "Unit Concentration."

The way that HARP usually works is for the program to automatically pass the "Unit Concentration" for a given source and receptor into its risk module where it is multiplied by the actual emission rate (in g/s) for each TAC and the "Unit Risk" for the TAC to produce the calculated risk for the TAC. This is done for all TACs emitted by a source and the summed cancer risk, or non-cancer health impact for common toxic endpoints in the case of chronic and acute risk, is the total risk or non-cancer health impact at that receptor from that source. The total cancer risk or non-cancer health impact at a receptor is the sum of the risks or health impacts from all of the sources.

Because HARP is not designed to pass AERMOD "Unit Concentration" outputs to its Risk Module, an alternative procedure can be used. The calculation of cancer risk or non-cancer health impact does not require the variables to be multiplied in any particular order. Therefore, the final result will be the same if, for a given source, the "Unit Risk" for a TAC is multiplied by the actual emissions (g/s) for the TAC, and these products are added together to give a "Source Strength" for the source. The "Source Strength" is then used as the source emission rate in AERMOD.

This special methodology thus uses HARP to calculate the "Unit Risks" for all carcinogenic TACs and unit chronic and acute health impacts for all non-carcinogenic TACs, including all required exposure pathways and toxic endpoints as well as receptor types, including residents and workers. The unit risk or unit health impact for each TAC from a source is multiplied by the emission rate of that TAC from the source. These products are summed for all TACs emitted by the source. This is done for each source. Finally, the resulting "Source Strengths" for each source are used as emission rates in an AERMOD calculation. The resulting risks are reported in the AERMOD output.

It is expected that the District will conclude that the new Diesel fire pump engine satisfies the requirements of toxics Best Available Control Technology, for which the maximum allowable cancer risk is 10 in one million.

13. FINAL MODELING SUBMITTAL

The final modeling analyses will include the following materials:

- Emissions calculations, modeled emission rates, and stack parameters (diameter, height, exit velocity, stack gas temperature, stack base height above sea level);
- Summaries of maximum modeled impacts for each air quality scenario;

- All modeling inputs and outputs (including BPIP-PRIME, ozone data and meteorological files) in electronic format, together with a description of all filenames;
- Plot plan showing emission points, nearby buildings (including dimensions), cross-section lines, property lines, fencelines, roads, and UTM coordinates;
- A table showing building heights used in the modeling analysis; and
- Concentration isopleths maps for each criteria pollutant and averaging time combination.

The HRA results will include AERMOD output files, spreadsheets that show the risk calculation procedures, a figure showing the locations of the maximum acute, chronic and cancer risks from the project, and a detailed description of the methodology.

14. REFERENCES

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Appendix A

Surface Parameters to be used for AERMET Stage 3 Processing

Surface Parameters to be Used for Stage 3 AERMET Processing
Gateway Generating Station

Spring - average

Sector	Land use (met station)	Suface roughness (m)	Land use (application site)	Albedo	Bowen ratio
1. 305^{0}-40^{0}	open water with distant shore	0.003	open water with distant shore	0.12	0.10
2. 40^{0}-90^{0}	open water	0.001	open water	0.12	0.10
3.90^{0}-120^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	1.00
4.120^{0}-200^{0}	Gentle slope with distant residences (grassland)	0.100	Gentle slope with distant residences (grassland)	0.18	0.40
5.200^{0}-270^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	1.00
6.270^{0}-305^{0}	open water	0.001	open water	0.12	0.10

Summer - dry

Sector	Land use (met station)	Suface roughness (m)	Land use (application site)	Albedo	Bowen ratio
1. 305^{0}-40^{0}	open water with distant shore	0.003	open water with distant shore	0.10	0.10
2. 40^{0}-90^{0}	open water	0.001	open water	0.10	0.10
3.90^{0}-120^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	4.00
4.120^{0}-200^{0}	Gentle slope with distant residences (grassland)	0.100	Gentle slope with distant residences (grassland)	0.18	2.00
5.200^{0}-270^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	4.00
6.270^{0}-305^{0}	open water	0.001	open water	0.10	0.10

Autumn - dry

Sector	Land use (met station)	Suface roughness (m)	Land use (application site)	Albedo	Bowen ratio
1. 305^{0}-40^{0}	open water with distant shore	0.003	open water with distant shore	0.14	0.10
2. 40^{0}-90^{0}	open water	0.001	open water	0.14	0.10
3.90^{0}-120^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	4.00
4.120^{0}-200^{0}	Gentle slope with distant residences (grassland)	0.100	Gentle slope with distant residences (grassland)	0.18	2.00
5.200^{0}-270^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	4.00
6.270^{0}-305^{0}	open water	0.001	open water	0.14	0.10

Winter - wet

Sector	Land use (met station)	Suface roughness (m)	Land use (application site)	Albedo	Bowen ratio
1. 305^{0}-40^{0}	open water with distant shore	0.003	open water with distant shore	0.20	0.10
2. 40^{0}-90^{0}	open water	0.001	open water	0.20	0.10
3.90^{0}-120^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	0.50
4.120^{0}-200^{0}	Gentle slope with distant residences (grassland)	0.100	Gentle slope with distant residences (grassland)	0.18	0.50
5.200^{0}-270^{0}	Industrial (urban)	0.600	Industrial (urban)	0.14	0.50
6.270^{0}-305^{0}	open water	0.001	open water	0.20	0.10

Sources for proposed parameter values:
USER'S GUIDE FOR THE AERMOD METEOROLOGICAL PREPROCESSOR (AERMET)

	Bowen ratio
0.10	Unfrozen water
1.00	Grassland - dry - spring
2.00	Grassland - dry - summer, autumn, winter
2.00	Urban - dry - spring, winter
4.00	Urban - dry - summer, autumn
0.30	Grassland - wet - spring
0.40	Grassland - wet - summer
0.50	Grassland - wet - autumn, winter
0.50	Urban - wet - spring, winter
1.00	Urban - wet - summer, autumn
0.40	Grassland - avg. - spring
0.80	Grassland - avg. - summer
1.00	Grassland - avg. - autumn
1.50	Grassland - avg. - winter
1.00	Urban - avg. - spring
2.00	Urban - avg. - summer, autumn
1.50	Urban - avg. - winter

	Albedo
0.12	Water - spring
0.10	Water - summer
0.14	Water - autumn
0.20	Water - winter
0.14	Urban
0.18	Grassland

from 'An Introduction to Boundary Layer Meteorology' by Roland B. Stull, Fig. 9.6, p. 380.

	Roughness Lengths (m)
0.600	Centers of small towns
0.100	Between 'many hedges' and 'many trees, hedges, and few buildings'
0.001	Approx. Off sea wind in coastal area
0.003	Marginally greater than 'Approx. Off sea wind in coastal area'

Appendix B

Information on CTDMPLUS Model

The CTDMPLUS and CTSCREEN Models

Complex terrain impacts may need to be modeled with more accuracy than that provided by AERMOD. The use of more refined modeling techniques is specifically addressed in EPA's Appendix W[5] modeling guidance, as follows:

> *Since AERMOD treats dispersion in complex terrain, we have merged sections 4 and 5 of appendix W, as proposed in the April 2000 NPR [Notice of Proposed Rulemaking]. And while AERMOD produces acceptable regulatory design concentrations in complex terrain, it does not replace CTDMPLUS for detailed or receptor-oriented complex terrain analysis, as we have made clear in Guideline section 4.2.2. CTDMPLUS remains available for use in complex terrain. [p. 68225]*
>
> *4.2.2 Refined Analytical Techniques*
> *d. If the modeling application involves a well defined hill or ridge and a detailed dispersion analysis of the spatial pattern of plume impacts is of interest, CTDMPLUS, listed in Appendix A, is available. CTDMPLUS provides greater resolution of concentrations about the contour of the hill feature than does AERMOD through a different plume-terrain interaction algorithm. [p. 68233]*

CTSCREEN is the same basic model as CTDMPLUS, except that meteorological data are handled internally in a simplified manner. As discussed in the CTSCREEN users guide,[6]

> *Since [CTDMPLUS] accounts for the three-dimensional nature of plume and terrain interaction, it requires detailed terrain and meteorological data that are representative of the modeling domain. Although the terrain data may be readily obtained from topographic maps and digitized for use in the CTDMPLUS, the required meteorological data may not be as readily available.*
>
> *Since the meteorological input requirements of the CTDMPLUS can limit its application, the EPA's Complex-Terrain-Modeling, Technology-Transfer Workgroup developed a methodology to use the advanced techniques of*

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[5] 40 CFR 51 Subpart W, as amended November 9, 2005 at 70 FR 68218, "Revision to the Guideline on Air Quality Models: Adoption of a Preferred General Purpose (Flat and Complex Terrain) Dispersion Model and Other Revisions."

[6] USEPA, EPA-600/8-90-087, "User's Guide to CTDMPLUS: Volume 2. The Screening Mode (CTSCREEN)," October 1990.

CTDMPLUS in situations where on-site meteorological measurements are limited or unavailable. This approach uses CTDMPLUS in a "screening" mode--actual source and terrain characteristics are modeled with an extensive array of predetermined meteorological conditions.

This CTDMPLUS screening mode (CTSCREEN) serves several purposes in regulatory applications. When meteorological data are unavailable, CTSCREEN can be used to obtain conservative (safely above those of refined models), yet realistic, impact estimates for particular sources.

Therefore, the use of the CTSCREEN version of CTDMPLUS is consistent with EPA guidance.

Meteorological Data for CTDMPLUS

The discussion in Section 4 of the protocol addresses meteorological data needed to run AERMOD. As discussed above, an additional model, Complex Terrain Dispersion Model PLUS (CTDMPLUS), may be used in lieu of the model Complex Terrain Screening Model (CTSCREEN) for receptors in the terrain above stack-top height. CTDMPLUS is a USEPA-approved air dispersion model, and is fully supported with user guidance documentation.[7]

CTDMPLUS requires an extensive suite of meteorological data composed of not only wind speed, direction, and temperature, but also horizontal and vertical wind direction standard deviations (sigma theta and sigma phi, respectively), and vertical wind speed standard deviation (sigma w). Many AERMOD-compatible meteorological data sets do not include these non-standard measurements.

It is possible to develop conservative values for the standard deviation parameters sigma theta, sigma phi, and sigma w that are consistent with the available meteorological data, and use them to prepare a meteorological data set that is usable in CTDMPLUS and yields conservative (i.e., high) ground-level concentrations.

If modeling with CTDMPLUS is required, the ISCST3-compatible meteorological data sets for the same four years (1994-1997) that was created for the original modeling analysis for the CC8 project would be used to create the CTDMPLUS-compatible meteorological data set. Because all three of these Gaussian dispersion models—ISCST3, AERMOD, and CTDMPLUS—require upper air data as well as surface data, the upper air data from Oakland would be used as discussed earlier.

The following meteorological parameters are needed for CTDMPLUS and would be taken directly from the AERMET files:

- Observed mixing height, provided as the height of the convective or planetary boundary layer (PBL);

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[7] USEPA. Technology Transfer Network, Support Center for Regulatory Atmospheric Modeling, *http://www.epa.gov/scram001/dispersion_prefrec.htm#ctdmplus*

- Calculated mixing height, provided as the height of the mechanical, or surface, boundary layer (SBL);
- Friction velocity (USTAR);
- Monin-Obukhov length (L); and
- Roughness length (Z_O).

The remaining standard deviations (sigma values) are not available from AERMOD and must be obtained from ISCST3-compatible met data files that were developed for the project. Stability classes determined by MPRM[8] or PCRAMMET[9] from the measured Pittsburg meteorological data would be used to select the most conservative values from the following ranges recommended in USEPA's Meteorological Monitoring Guidance document:[10]

Stability Category	Sigma Phi (σ_Φ)/ Regulatory Range (degrees)	Sigma Theta (σ_θ)/ Regulatory Range (degrees)
A	11.5	22.5
B	10.0 – 11.5	17.5 – 22.5
C	7.8 – 10.0	12.5 – 17.5
D	5.0 – 7.8	7.5 – 12.5
E	2.4 – 5.0	3.8 – 7.5
F	< 2.4	< 3.8

The most conservative values (that is, the values that produce the highest modeled impacts) for sigma theta and sigma phi within each range would be determined by conducting a sensitivity analysis for all combinations of stack conditions to be modeled using CTDMPLUS and receptor locations for which CTDMPLUS would be used (that is, receptors above stack height). The sensitivity analysis would use the upper and lower values of each range for each stability category. For example, for stability category D, four combinations would be evaluated as follows:

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[8] The Meteorological Processor for Regulatory Models

[9] EPA meteorological preprocessor

[10] Tables 6-8a and 6-9a in Meteorological Monitoring Guidance for Regulatory Modeling Applications, EPA-454/R-99-005, US EPA Office of Air and Radiation, Office of Air Quality Planning and Standards, February 2000.

σ_Φ	σ_θ
5.0	7.5
5.0	12.5
7.8	7.5
7.8	12.5

For stability category A, maximum values for σ_Φ and σ_θ of 15.0 and 27.0, respectively, would be evaluated. For stability category F, minimum values for σ_Φ and σ_θ of 1.0 and 2.0, respectively, would be evaluated.

Sigma w would be estimated by multiplying sigma-phi (after conversion from degrees to radians) by the horizontal wind speed.

Attachment B-2

Documentation for AERMET Surface Parameters

AERMET Surface Parameters
for Northern Sectors

	Sector 1					Sector 2					Sector 6				
	321 deg to 53 deg					53 deg to 90 deg					270 deg to 321 deg				
	cultivated farmland		50%			swamp		10%			swamp		34%		
	swamp		10%			industrial		20%			industrial		5%		
	industrial		3%			water		70%			water		61%		
	water		37%												
Month	Suface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio	Suface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio	Suface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio
JAN	0.0400	0.1632	0.457	0.457	0.457	0.2051	0.15	0.480	0.480	0.480	0.0671	0.1488	0.195	0.195	0.195
FEB	0.0400	0.1632	0.457	0.457	0.457	0.2051	0.15	0.480	0.480	0.480	0.0671	0.1488	0.195	0.195	0.195
MAR	0.0650	0.1306	0.617	0.227	0.227	0.2201	0.124	0.490	0.280	0.280	0.1181	0.121	0.229	0.145	0.145
APR	0.0650	0.1306	0.617	0.227	0.162	0.2201	0.124	0.490	0.280	0.180	0.1181	0.121	0.229	0.145	0.12
MAY	0.0650	0.1306	0.617	0.227	0.617	0.2201	0.124	0.490	0.280	0.490	0.1181	0.121	0.229	0.145	0.229
JUN	0.1500	0.1558	0.927	0.357	0.927	0.2201	0.116	0.890	0.480	0.890	0.1181	0.1166	0.329	0.195	0.329
JUL	0.1500	0.1558	0.927	0.927	0.927	0.2201	0.116	0.890	0.890	0.890	0.1181	0.1166	0.329	0.329	0.329
AUG	0.1500	0.1558	0.927	0.927	0.927	0.2201	0.116	0.890	0.890	0.890	0.1181	0.1166	0.329	0.329	0.329
SEP	0.0750	0.1632	1.177	1.177	1.177	0.2201	0.15	0.890	0.890	0.890	0.1181	0.1488	0.329	0.329	0.329
OCT	0.0750	0.1632	0.277	1.177	1.177	0.2201	0.15	0.280	0.890	0.890	0.1181	0.1488	0.145	0.329	0.329
NOV	0.0750	0.1632	0.457	1.177	1.177	0.2201	0.15	0.480	0.890	0.890	0.1181	0.1488	0.195	0.329	0.329
DEC	0.0400	0.1632	0.277	0.277	0.457	0.2051	0.15	0.280	0.280	0.480	0.0671	0.1488	0.145	0.145	0.195
ANN	0.0825	0.1532	0.6445	0.6345	0.7241	0.2163	0.135	0.5858	0.5842	0.6442	0.1053	0.1338	0.2398	0.2342	0.2544

AERMET Surface Parameters
for Southern Sectors
Provided by the BAAQMD Staff

	Sector 2: 53 deg to 90 deg					Sector 3: 90 deg to 120 deg					Sector 4: 120 deg to 270 deg				
Month	Surface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio	Surface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio	Surface roughness	Albedo	2004 Bowen ratio	2005 Bowen ratio	2006 Bowen ratio
JANUARY	0.1514	0.1149	0.3322	0.3322	0.3322	0.6651	0.1542	1.1974	1.1974	1.1974	0.6360	0.1687	1.3117	1.3117	1.3117
FEBRUARY	0.1516	0.1147	0.3304	0.3304	0.3304	0.6672	0.1530	1.1931	1.1931	1.1931	0.6346	0.1595	1.2102	1.2102	1.2102
MARCH	0.1516	0.1147	0.5972	0.3304	0.3304	0.6672	0.1530	2.3833	1.1931	1.1931	0.6346	0.1595	2.4578	1.2102	1.2102
APRIL	0.1517	0.1147	0.5995	0.3313	0.2477	0.6691	0.1536	2.3887	1.1952	0.8083	0.6486	0.1643	2.5700	1.2613	0.8622
MAY	0.1517	0.1147	0.5995	0.3313	0.5995	0.6691	0.1536	2.3887	1.1952	2.3887	0.6486	0.1643	2.5700	1.2613	2.5700
JUNE	0.1517	0.1147	0.5995	0.3313	0.5995	0.6691	0.1536	2.3887	1.1952	2.3887	0.6486	0.1643	2.5700	1.2613	2.5700
JULY	0.1515	0.1148	0.6006	0.6006	0.6006	0.6671	0.1539	2.3913	2.3913	2.3913	0.6423	0.1665	2.6244	2.6244	2.6244
AUGUST	0.1515	0.1148	0.6006	0.6006	0.6006	0.6671	0.1539	2.3913	2.3913	2.3913	0.6423	0.1665	2.6244	2.6244	2.6244
SEPTEMBER	0.1515	0.1148	0.6006	0.6006	0.6006	0.6671	0.1539	2.3913	2.3913	2.3913	0.6423	0.1665	2.6244	2.6244	2.6244
OCTOBER	0.1515	0.1148	0.2479	0.6006	0.6006	0.6671	0.1539	0.8088	2.3913	2.3913	0.6423	0.1665	0.8732	2.6244	2.6244
NOVEMBER	0.1514	0.1149	0.3322	0.6018	0.6018	0.6651	0.1542	1.1974	2.3940	2.3940	0.6360	0.1687	1.3117	2.6788	2.6788
DECEMBER	0.1514	0.1149	0.2481	0.2481	0.3322	0.6651	0.1542	0.8094	0.8094	1.1974	0.6360	0.1687	0.8843	0.8843	1.3117
ANNUAL	0.1515	0.1148	0.3315	0.3315	0.3315	0.6671	0.1538	1.1958	1.1958	1.1958	0.6410	0.1653	1.2738	1.2738	1.2738

AERMET Land Use Parameters

Climatology for Bowen Ratio (from BAAQMD)

		2004	2005	2006
Winter	JAN	average	average	average
	FEB	average	average	average
Spring	MAR	dry	average	average
	APR	dry	average	wet
	MAY	dry	average	dry
Summer	JUN	dry	average	dry
	JUL	dry	dry	dry
	AUG	dry	dry	dry
Fall	SEP	dry	dry	dry
	OCT	wet	dry	dry
	NOV	average	dry	dry
Winter	DEC	wet	wet	average
	ANN	average	average	average

ALBEDO OF GROUND COVERS BY LAND-USE AND SEASON

Land-Use	Spring	Summer	Autumn	Winter in this project*	Winter
Water (fresh and sea)	0.12	0.1	0.14	0.14	0.2
Deciduous Forest	0.12	0.12	0.12	0.12	0.5
Coniferous Forest	0.12	0.12	0.12	0.12	0.35
Swamp	0.12	0.14	0.16	0.16	0.3
Cultivated Land	0.14	0.2	0.18	0.18	0.6
Grassland	0.18	0.18	0.2	0.2	0.6
Urban	0.14	0.16	0.18	0.18	0.35
Desert Shrubland	0.3	0.28	0.28	0.28	0.45

* The winter Albedo in the project area is similar to that of autumn because there is no ice season.

AERMET Land Use Parameters

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
DRY CONDITIONS

Land-Use	Spring	Summer	Autumn	Winter in this project*	Winter
Water (fresh and sea)	0.1	0.1	0.1	0.1	2
Deciduous Forest	1.5	0.6	2	2	2
Coniferous Forest	1.5	0.6	1.5	1.5	2
Swamp	0.2	0.2	0.2	0.2	2
Cultivated Land	1	1.5	2	2	2
Grassland	1	2	2	2	2
Urban	2	4	4	4	2
Desert Shrubland	5	6	10	10	10

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
AVERAGE CONDITIONS

Land-Use	Spring	Summer	Autumn	Winter in this project*	Winter
Water (fresh and sea)	0.1	0.1	0.1	0.1	1.5
Deciduous Forest	0.7	0.3	1	1	1.5
Coniferous Forest	0.7	0.3	0.8	0.8	1.5
Swamp	0.1	0.1	0.1	0.1	1.5
Cultivated Land	0.3	0.5	0.7	0.7	1.5
Grassland	0.4	0.8	1	1	1.5
Urban	1	2	2	2	1.5
Desert Shrubland	3	4	6	6	6

DAYTIME BOWEN RATIO BY LAND USE AND SEASON
WET CONDITIONS

Land-Use	Spring	Summer	Autumn	Winter in this project*	Winter
Water (fresh and sea)	0.1	0.1	0.1	0.1	0.3
Deciduous Forest	0.3	0.2	0.4	0.4	0.5
Coniferous Forest	0.3	0.2	0.3	0.3	0.3
Swamp	0.1	0.1	0.1	0.1	0.5
Cultivated Land	0.2	0.3	0.4	0.4	0.5
Grassland	0.3	0.4	0.5	0.5	0.5
Urban	0.5	1	1	1	0.5
Desert Shrubland	1	1.5	2	2	2

* The winter Bowen ratio in the project area are similar to that of autumn, because of the unique seasonal characteristics in Bay Area.

SURFACE ROUGHNESS LENGTH, IN METERS, BY LAND-USE AND SEASON

Land-Use	Spring	Summer	Autumn	Winter
Water (fresh and sea)	0.0001	0.0001	0.0001	0.0001
Deciduous Forest	1	1.3	0.8	0.5
Coniferous Forest	1.3	1.3	1.3	1.3
Swamp	0.2	0.2	0.2	0.05
Cultivated Land	0.03	0.2	0.05	0.01
Grassland	0.05	0.1	0.01	0.001
Urban	1	1	1	1
Desert Shrubland	0.3	0.3	0.3	0.15

** All values extracted from "USER’S GUIDE FOR THE AERMOD METEOROLOGICAL PREPROCESSOR (AERMET)"

Appendix C

Screening Health Risk Assessment

Screening Health Risk Assessment

The screening level health risk assessment has been prepared using CARB's Hotspots Analysis and Reporting Program (HARP) computer program (Version 1.2a, August 26, 2005) and associated guidance in the OEHHA's *Air Toxics Hot Spots Program Guidance Manual for Preparation of Health Risk Assessments* (August 2003). The HARP model was used to assess cancer risk as well as chronic and acute risk impacts. The following paragraphs describe the procedures used to prepare this risk assessment.

Modeling Inputs

The risk assessment module of the HARP model was run using unit ground level impacts to obtain derived cancer risks for each toxic chemical of interest.[1] Cancer risks were obtained for the derived (adjusted) method and the derived (OEHHA) method (for worker exposure) options. The HARP model output was cancer risk by pollutant and route for each type of analysis, based on an exposure of 1.0 $\mu g/m^3$. Individual cancer risks are expressed in units of risk per $\mu g/m^3$ of exposure. To calculate the weighted risk for each source, the annual average emission rate in g/s for each pollutant was multiplied by the individual cancer risk for that pollutant in $(\mu g/m^3)^{-1}$. The resulting weighted cancer risks for each pollutant were then summed for the source. An identical approach was used to determine the acute and chronic health impacts associated with the proposed project. Details of the calculations of risk "rates" for modeling are shown in Tables C-1 through C-4.

Risk Analysis Method

The results of the turbine screening analysis (see Appendix B, Table B-3) were used to determine the worst-case full load operating conditions for modeling for the annual and 1-hour averaging periods, used in determining cancer risk and chronic HHI, and acute HHI, respectively. The total weighted risk "rate" for each source was used in place of emission rates in the modeling analysis. The weighted risk "rates" used for the HRA modeling are summarized in Table C-5. The calculated value was then total cancer risk at each receptor. As discussed in Part III of the application, the screening analysis for the criteria pollutant modeling analysis was performed using the AERMOD model, the 2004 through 2006 Contra Costa meteorological data, specific receptor grids, and the stack parameters for eight operating cases. The exhaust characteristics for the highest full-load 1-hour and annual average unit impacts from the screening analysis, Case 5, was used to model cancer risks from the turbines for the proposed project.

As shown in Table 13, the cancer risk from the project is slightly above 1 in one million, due to the Diesel particulate matter emissions from the fire pump engine. However, since the fire pump engine particulate emission limit meets Toxics BACT levels and the cancer risk is well below 10 in one million, the project can be approved. In addition, the area where the cancer risk exceeds 1 in one million barely crosses the facility fenceline so it is extremely unlikely that anyone will experience the maximum modeled risk. Finally, the acute and chronic health hazard indices are well below the significance level of one.

[1] Procedure is described in Part B of Topic 8 of the HARP How-To Guides: How to Perform Health Analyses Using a Ground Level Concentration.

The analysis of potential cancer risk described in this section employs extremely conservative methods and assumptions, as follows:

- The analysis includes representative weather data over 3 years to ensure that the least favorable conditions producing the highest ground-level concentration of power plant emissions are included. The analysis then assumes that these worst-case weather conditions, which in reality occurred only once in 3 years, will occur every year for 70 years.
- The analysis assumes that a sensitive individual is at the location of the highest ground-level concentration of power plant emissions continuously over the entire 70-year period. In reality, people rarely live in their homes for 70 years, and even if they do, they leave their homes to attend school, go to work, go shopping, and so on. Further, as described above, the highest ground-level impact occurs near the fenceline of the facility, where there are no residences or other sensitive receptors.

The point of using these unrealistic assumptions is to consciously overstate the potential impacts. No one will experience exposures as great as those assumed for this analysis. By determining that even this highly overstated exposure will not be significant, there is a high degree of confidence that the much lower exposures that actual persons will experience will not result in a significant increase in cancer risk. In short, the analysis ensures that there will not be significant public health impacts at any location, under any weather condition, under any operating condition.

Table C-1
Gateway Generating Station
Calculation of Modeling Inputs for CTG/HRSG Cancer Risk Assessment

		Derived (Adjusted) Method		Worker Exp: Derived (OEHHA) Method	
Compound	Annual Average Emissions Per Engine g/s	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3 per g/s)	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3 per g/s)
Ammonia	3.37E+00	0	0	0	0
Propylene	1.91E-01	0	0	0	0
Acetaldehyde	1.01E-02	2.90E-06	2.93E-02	5.72E-07	5.79E-03
Acrolein	9.15E-04	0	0	0	0
Benzene	8.26E-04	2.90E-05	2.40E-02	5.72E-06	4.72E-03
1,3-Butadiene	1.09E-04	1.74E-04	1.89E-02	3.43E-05	3.73E-03
Ethylbenzene	8.09E-03	0	0	0	0
Formaldehyde	9.10E-02	6.08E-06	5.53E-01	1.20E-06	1.09E-01
Hexane	6.42E-02	0	0	0	0
Naphthalene	4.12E-04	3.48E-05	1.43E-02	6.86E-06	2.82E-03
PAHs (Note 1)	1.13E-05	1.65E-02	1.87E-01	1.47E-02	1.66E-01
Propylene Oxide	7.39E-03	3.76E-06	2.78E-02	7.43E-07	5.49E-03
Toluene	3.30E-02	0	0	0	0
Xylene	1.62E-02	0	0	0	0
			8.55E-01 per ug/m3		2.98E-01 per ug/m3

Notes:
(1) Emission rates for individual PAHs weighted by risk relative to B(a)P. See Table A-6.

Table C-2
Gateway Generating Station
Calculation of Modeling Inputs and HHIs for CTG Acute and Chronic Risk Assessment

Compound	Acute Health Impacts			Chronic Health Impacts		
	Max Hourly Emissions Per Engine g/s	HARP Acute HI (per ug/m3)	Acute HHI Model Input (per ug/m3 per g/s)	Annual Average Emissions, g/s	HARP Chronic HI (per ug/m3)	Chronic HHI Model Input (per ug/m3 per g/s)
Ammonia	3.54E+00	3.13E-04	1.11E-03	3.367	5.00E-03	1.68E-02
Propylene	2.01E-01	--	--	0.191	3.33E-04	6.37E-05
Acetaldehyde	1.06E-02	--	--	1.01E-02	1.11E-01	1.12E-03
Acrolein	9.62E-04	5.26E+00	5.06E-03	9.15E-04	1.67E+01	1.53E-02
Benzene	8.68E-04	7.69E-04	6.68E-07	8.26E-04	1.67E-02	1.38E-05
1,3-Butadiene	1.14E-04	--	--	1.09E-04	5.00E-02	--
Ethylbenzene	8.50E-03	--	--	8.09E-03	5.00E-04	4.04E-06
Formaldehyde	9.57E-02	1.06E-02	1.01E-03	9.10E-02	3.33E-01	3.03E-02
Hexane	6.75E-02	--	--	6.42E-02	1.43E-04	9.19E-06
Naphthalene	4.33E-04	--	--	4.12E-04	1.11E-01	4.57E-05
PAHs	1.19E-05	--	--	1.13E-05	--	--
Propylene Oxide	7.77E-03	3.23E-04	2.51E-06	7.39E-03	3.33E-02	2.46E-04
Toluene	3.47E-02	2.70E-05	9.36E-07	3.30E-02	3.33E-03	1.10E-04
Xylene	1.70E-02	4.55E-05	7.75E-07	1.62E-02	1.43E-03	2.32E-05
		Total =	7.19E-03		Total =	6.41E-02

Table C-3
Gateway Generating Station
Cancer Risk Assessment Modeling Inputs for Other Equipment

Dewpoint Heater

		Derived (Adjusted) Method		Worker Exp: Derived (OEHHA) Method	
Compound	Annual Average Emissions	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3
Ammonia	--	0	0	0	0
Propylene	5.90E-04	0	0	0	0
Acetaldehyde	3.48E-06	2.90E-06	1.01E-05	5.72E-07	1.99E-06
Acrolein	2.18E-06	0	0	0	0
Benzene	6.47E-06	2.90E-05	1.88E-04	5.72E-06	3.70E-05
1,3-Butadiene	--	1.74E-04	0.00E+00	3.43E-05	0.00E+00
Ethylbenzene	7.68E-06	0	0	0	0
Formaldehyde	1.37E-05	6.08E-06	8.36E-05	1.20E-06	1.65E-05
Hexane	5.09E-06	0	0	0	0
Naphthalene	2.43E-07	3.48E-05	8.44E-06	6.86E-06	1.66E-06
PAHs (Note 1)	8.09E-08	1.65E-02	1.33E-03	1.47E-02	1.19E-03
Propylene Oxide	--	3.76E-06	0	7.43E-07	0
Toluene	2.96E-05	0	0	0	0
Xylene	2.20E-05	0	0	0	0
			1.62E-03 per ug/m3		1.25E-03 per ug/m3

Fire Pump Engine

		Derived (Adjusted) Method		Worker Exposure: Derived (OEHHA) Method	
Compound	Annual Average Emissions, g/s	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3 per g/s)	Unit Risk (per ug/m3)	Cancer Risk Model Input (per ug/m3 per g/s)
Diesel Exhaust Particulate	5.71E-05	3.19E-04	1.82E-02 per ug/m3	6.29E-05	3.59E-03 per ug/m3

Table C-4
Gateway Generating Station
Calculation of Modeling Inputs and HHIs for Other Equipment Acute and Chronic Risk Assessment

Dewpoint Heater

	Acute Health Impacts			Chronic Health Impacts		
Compound	Max Hourly Emissions, g/s	HARP Acute HI (per ug/m3)	Acute HHI Model Input (per ug/m3 per g/s)	Annual Average Emissions, g/s	HARP Chronic HI (per ug/m3)	Chronic HHI Model Input (per ug/m3 per g/s)
Propylene	5.90E-04	--	--	5.90E-04	3.33E-04	1.97E-07
Acetaldehyde	3.48E-06	--	--	3.48E-06	1.11E-01	3.86E-07
Acrolein	2.18E-06	5.26E+00	1.15E-05	2.18E-06	1.67E+01	3.65E-05
Benzene	6.47E-06	7.69E-04	4.97E-09	6.47E-06	1.67E-02	1.08E-07
1,3-Butadiene	--	--	--	--	5.00E-02	--
Ethylbenzene	7.68E-06	--	--	7.68E-06	5.00E-04	3.84E-09
Formaldehyde	1.37E-05	1.06E-02	1.46E-07	1.37E-05	3.33E-01	4.58E-06
Hexane	5.09E-06	--	--	5.09E-06	1.43E-04	7.29E-10
Naphthalene	2.43E-07	--	--	2.43E-07	1.11E-01	2.69E-08
PAHs	8.09E-08	--	--	8.09E-08	--	--
Propylene Oxide	--	3.23E-04	--	--	3.33E-02	--
Toluene	2.96E-05	2.70E-05	7.99E-10	2.96E-05	3.33E-03	9.86E-08
Xylene	2.20E-05	4.55E-05	1.00E-09	2.20E-05	1.43E-03	3.15E-08
		Total =	1.16E-05		Total =	4.19E-05

Fire Pump Engine

Compound	Max Hourly Emissions for Em Gen. g/s	HARP Acute HI (per ug/m3)	Acute HHI Model Input (per ug/m3 per g/s)	Annual Average Emissions, g/s	HARP Chronic HI (per ug/m3)	Chronic HHI Model Input (per ug/m3 per g/s)
Particulate Em from Diesel-Fueled Engines	1.00E-02	n/a	n/a	5.71E-05	2.00E-01	1.14E-05
					Total =	1.14E-05

Table C-5
Gateway Generating Station
Summary of Modeling Input Values for Screening HRA

Unit	Derived (Adjusted) Method Cancer Risk (Res)	Derived (OEHHA) Method Cancer Risk (Worker)	Chronic HHI Model Input (per ug/m3)	Acute HHI Model Input (per ug/m3)
CTGs (each)	8.547E-01	2.983E-01	6.407E-02	7.187E-03
Dewpoint Heater	1.624E-03	1.246E-03	4.189E-05	1.164E-05
Diesel fire pump engine	1.821E-02	3.590E-03	1.142E-05	-

All modeling input values are in units of per ug/m3

Stack Parameters				
	Stack Diam (m)	Stack Ht (m)	Exhaust Temp (deg K)	Exhaust Velocity (m/s)
CTGs (each)	5.108	59.436	355.222	19.923
Dewpoint Heater	0.203	4.715	422.039	28.719
Diesel fire pump engine	0.154	3.251	683.150	44.058

Appendix D

Revised Permit Conditions

Gateway Generating Station Permit Conditions

Definitions:

1-hour period: Any continuous 60-minute period beginning on the hour.

Calendar Day: Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.

Year: Any consecutive twelve-month period of time

Heat Input: All heat inputs refer to the heat input at the higher heating value fuel, in Btu/scf.

Rolling 3-hour period: Any three-hour period that begins on the hour and does not include start-up or shutdown periods.

Firing Hours: Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.

MM Btu: million British thermal units

Gas Turbine Start-up Mode: The lesser of the first 360 minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).

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Gas Turbine Shutdown Mode: The lesser of the 60 minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(a) through 20(d) until termination of fuel flow to the Gas Turbine.

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Specified PAHs: The polycyclic aromatic hydrocarbons listed below shall be considered to Specified PAHs for these permit conditions. Any emission limits for Specified PAHs refer to the sum of the emissions for all six of the following compounds.

Benzo[a]anthracene

Benzo[b]fluoranthene

Benzo[k]fluoranthene

Benzo[a]pyrene

Dibenzo[a,h]anthracene

Indeno[1,2,3-cd]pyrene

Corrected Concentration: The concentration of any pollutant (generally NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the GGS construction contractor to insure safe and reliable steady state

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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 and is available for commercial operation.

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Combustor Tuning Activities: All testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer or an independent qualified contractor to insure safe and reliable steady state operation of the gas turbines following replacement of the combustor. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize NOx and CO production while minimizing combustor dynamics and ensuring combustor stability.

Combustor Tuning Period: The period, not to exceed 360 minutes, during which gas turbine combustor tuning activities are taking place.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

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CEC CPM: California Energy Commission Compliance Program Manager

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CCPP Unit#8: Contra Costa Power Plant Unit 8

GGS: Gateway Generating Station

Conditions for the Commissioning Period

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

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

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

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

5. The owner/operator of the GGS shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas

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Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired dewpoint heater. 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-NOx combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

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6. During the commissioning period, the owner/operator of the GGS shall demonstrate compliance with conditions 8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

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- firing hours for each gas turbine and each HRSG
- fuel flow rates to each train
- stack gas nitrogen oxide emission concentrations at P-11 and P-12
- stack gas carbon monoxide emission concentrations P-11 and P-12
- stack gas carbon dioxide or oxygen concentrations P-11 and P-12

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

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

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

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

District Permit Services and Enforcement Divisions and the unused balance of the 500 firing hours without abatement shall expire.

10. The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition 24.

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

NOx (as NO2)	8,400 pounds/calendar day	400 pounds/hour
CO	40,000 pounds/calendar day	4,000 pounds/hour
POC(as CH4)	1,600 pounds/calendar day	
PM10	432 pounds/calendar day	
SO2	297 pounds/calendar day	

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12. Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with condition 21. The source test shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

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

13. The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for SO2 and PM10)

14. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 2,094.4 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NOx)

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15. The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for PM10)

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

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

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

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

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

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(a) Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO_2) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed 15.2 pounds per hour or 0.0072 lb./MM Btu (HHV) of natural gas fired. (PSD for NOx)

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(b) The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed 2.0 ppmv, on a dry basis, corrected to 15% O_2, averaged over any 1-hour period. (BACT for NOx)

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(c) Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed 0.0088 lb./MM Btu (HHV) of natural gas fired or 18.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

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(d) The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed 4 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. (BACT for CO)

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(e) Ammonia (NH_3) emission concentrations at P-11 and P-12 each shall not exceed 10 ppmv, on a dry basis, corrected to 15% O_2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for NH_3)

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(f) Precursor organic compound (POC) mass emissions (as CH_4) at P-11 and P-12 each shall not exceed 5.3 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

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(g) Sulfur dioxide (SO_2) mass emissions at P-11 and P-12 each shall not exceed 5.92 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

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(h) Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or 0.0095 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 12 pounds per hour or 0.0065 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

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(i) Compliance with the hourly NOx emission limitations specified in condition 20(a) and 20(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the owner/operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O2. Examples of transient load conditions include, but are not limited to the following:

(1) Initiation/shutdown of combustion turbine inlet air cooling

(2) Rapid combustion turbine load changes

(3) Initiation/shutdown of HRSG duct burners

The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmv, dry @ 15% O2. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

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

	Start-Up or Combustor Tuning Period (lb./period)	Startup/Shutdown (lb./hr)
Oxides of Nitrogen (as NO2)	600	160
Carbon Monoxide (CO)	5,400	900
Precursor Organic Compounds (as CH4)	96	16

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

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

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(a) 1,994 pounds of NOx (as NO2) per day (CEQA)

(b) 11,470 pounds of CO per day (PSD)

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(c) 468 pounds of POC (as CH4) per day (CEQA)

(d) 577 pounds of PM10 per day (PSD)

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(e) 297 pounds of SO2 per day (BACT)

24. Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44) and the Dewpoint Heater (S-45) and the Diesel Fire Pump Engine (S-48), including emissions generated during gas turbine start-ups, shutdowns and combustor tuning periods shall not exceed the following limits during any consecutive twelve-month period:

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Deleted: Cooling Tower

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(a) 174.3 tons of NOx (as NO_2) per year (Offsets, PSD)

(b) 555.4 tons of CO per year (Cumulative Increase)

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(c) 46.6 tons of POC (as CH_4) per year (Offsets)

(d) 101.7 tons of PM10 per year (Offsets, PSD)

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(e) 37.0 tons of SO_2 per year (Cumulative Increase)

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25. Toxic and HAP Emission Limits

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

12,656 pounds of formaldehyde per year

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115 pounds of benzene per year

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6.2 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

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unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 10.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

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

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

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

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

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(a) Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(b) Carbon Dioxide (CO_2) or Oxygen (O_2) concentrations, Nitrogen Oxides (NOx) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.

(c) Ammonia injection rate at A-11 and A-13 SCR Systems

(d) Steam injection rate at S-41 & S-43 Gas Turbine Combustors

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

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

(e) Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

(f) Corrected NOx concentrations, NOx mass emissions (as NO2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and 26(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 four sources (S-41, S-42, S-43, and S-44) combined.

(i) the average NOx mass emissions (as NO2), CO mass emissions, and corrected NOx and CO emission concentrations for every clock hour and for every rolling 3-hour period.

(j) on an hourly basis, the cumulative total NOx mass emissions (as NO2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.

(k) For each calendar day, the average hourly Heat Input Rates, Corrected NOx emission concentrations, NOx mass emissions (as NO2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

(l) on a daily basis, the cumulative total NOx mass emissions (as NO2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

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

27. To demonstrate compliance with conditions 20(f), 20(g), 20(h), 23(c) through 23(e), and 24(c) through 24(e), the owner/operator shall calculate and record on a daily basis, the Precursor Organic Compound (POC) mass emissions, Fine Particulate Matter (PM10) mass emissions (including condensable particulate matter), and Sulfur Dioxide (SO2) mass emissions from each power train. The owner/operator shall use the actual Heat Input Rates calculated pursuant to condition 26, actual Gas Turbine Start-up Times, actual Gas Turbine Shutdown Times, and CEC and District-approved emission factors to calculate these emissions. The calculated emissions shall be presented as follows:

(a) For each calendar day, POC, PM10, and SO2 emissions shall be summarized for: each power train (Gas Turbine and its respective HRSG combined) and all four sources (S-41, S-42, S-43, and S-44) combined.

(b) on a daily basis, the 365 day rolling average cumulative total POC, PM10, and SO2 mass emissions, for all four sources (S-41, S-42, S-43, and S-44) combined.

(Offsets, PSD, Cumulative Increase)

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

29. Within 60 days of start-up of the GGS, the owner/operator shall conduct a District-approved source est on exhaust point P-11 or P-12 to determine the corrected ammonia (NH3) emission concentration to determine compliance with condition 20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding NH3 emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. Continuing compliance with condition 20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

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30. Within 60 days of start-up of the GGS and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load to determine compliance with Conditions 20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions 20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition 26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM10) emissions including condensable particulate matter. (BACT, offsets)

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31. The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used

to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

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

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Benzene	less than or equal	26.8 pounds/year
Formaldehyde	less than or equal	132 pounds/year
Specified PAHs	less than or equal	0.18 pounds/year

(TRMP)

33. The owner/operator of the GGS 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)

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34. The owner/operator of the GGS 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)

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35. The owner/operator of the GGS 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)

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

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

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

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39. Prior to the issuance of the BAAQMD Authority to Construct for the GGS, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of

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200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and 101.7 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

40. Prior to the start of construction of the GGS, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and 101.7 tons of Particulate Matter less than 10 microns. (Offsets)

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

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

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

44. The owner/operator shall take quarterly samples of the natural gas combusted at the GGS. The samples shall be analyzed for sulfur content using District- approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content of each individual sample shall be no more than 1.0 grains/100 scf. Average sulfur content of four quarterly samples shall be no more than 0.75 grains/100 scf. (cumulative increase)

45. [deleted]46. [deleted]47. The Dewpoint Heater (S-45) shall not be fired more than 156 MMBtu/day. (BACT)

Conditions for S-48 Emergency Fire Pump Engine

48. Operation of S-48 for reliability-related activities is limited to 50 hours per year. (Stationary Diesel Engine ATCM)

49. The owner/operator shall operate engine S-48 only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits is not limited. (Stationary Diesel Engine ATCM)

50. The owner/operator shall operate engine S-48 only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. (Stationary Diesel Engine ATCM)

51. Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 36 months from the date of entry. Log entries shall be

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Deleted: The cooling towers shall be properly installed and maintained to minimize drift losses. The cooling towers shall be equipped with high-efficiency mist eliminators with a maximum guaranteed drift rate of 0.0005%. The maximum total dissolved solids (TDS) measured at the base of the cooling towers or at the point of return to the wastewater facility shall not be higher than 5,666 ppmw (mg/l). The owner/operator shall sample the water at least once per day. (PSD)

Deleted: The owner/operator shall perform a visual inspection

Deleted: f the cooling tower drift eliminators at least once per calendar year, and repair or replace any drift eliminator components which are broken or missing. Prior to the initial operation of the CCPP Unit 8, the owner/operator shall have the cooling tower vendor's field representative inspect the cooling tower drift eliminators and certify that the installation was performed in a satisfactory manner. The CEC CPM may, in years 5 and 15 of cooling tower operation, require the owner/operator to perform a source test to determine the PM10 emission rate from the cooling tower to verify compliance with the vendor-guaranteed drift rate specified in condition 45. (PSD) ¶

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retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. (Stationary Diesel Engine ATCM)

a. Hours of operation of S-48 for reliability-related activities (maintenance and testing).

b. Hours of operation of S-48 for emission testing to show compliance with emission limits.

c. Hours of emergency operation of S-48.

d. For each emergency, the nature of the emergency condition.

e. Fuel usage for S-48.

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

Form P-101B
Authority to Construct/
Permit to Operate

1. Application Information

BAAQMD Plant No. 18143 Company Name Gateway Generating Station

Equipment/Project Description two natural gas-fired combustion turbine generators with duct firing and aux. eqt.

2. Plant Information *If you have not previously been assigned a Plant Number by the District or if you want to update any plant data that you have previously supplied to the District, please complete this section.*

Equipment Location 3225 Wilbur Avenue

City Antioch, CA Zip Code 94509

Mail Address 77 Beale St, Mail Stop B24A

City San Francisco State CA Zip Code 94105

Plant Contact Angel Espiritu Title Sr. Environmental Specialist

Telephone (925) 459-7212 Fax (925) 459-7223 Email ABE4@pge.com

NAICS (North American Industry Classification System) see www.census.gov/epcd/naics02/naico602.htm 221112

3. Proximity to a School (K-12)

The sources in this permit application (*check one*) ☐ Are ☑ Are not within 1,000 ft of the outer boundary of the nearest school.

4. Application Contact Information *All correspondence from the District regarding this application will be sent to the plant contact unless you wish to designate a different contact for this application.*

Application Contact Tom Allen Title Project Manager

Mail Address 3225 Wilbur Avenue

City Antioch State CA Zip Code 94509

Telephone (925) 459-7200 Fax ( ) Email HTA1@pge.com

5. Additional Information *The following additional information is required for all permit applications and should be included with your submittal. Failure to provide this information may delay the review of your application. Please indicate that each item has been addressed by checking the box. Contact the Engineering Division if you need assistance.*

☐ If a new Plant, a local street map showing the location of your business
☑ A facility map, drawn roughly to scale, that locates the equipment and its emission points
☑ Completed data form(s) and a pollutant flow diagram for each piece of equipment. (See www.baaqmd.gov/pmt/forms/)
☑ Project/equipment description, manufacturer's data
☑ Discussion and/or calculations of the emissions of air pollutants from the equipment

6. Trade Secrets *Under the California Public Records Act, all information in your permit application will be considered a matter of public record and may be disclosed to a third party. If you wish to keep certain items separate as specified in Regulation 2, Rule 1, Section 202.7, please complete the following steps.*

☐ Each page containing trade secret information must be labeled "trade secret" with the trade secret information clearly marked.
☐ A second copy, with trade secret information blanked out, marked "public copy" must be provided.
☐ For each item asserted to be trade secret, you must provide a statement which provides the basis for your claim.

7. Small Business Certification *You are entitled to a reduced permit fee if you qualify as a small business as defined in Regulation 3. In order to qualify, you must certify that your business meets all of the following criteria:*

☐ The business does not employ more than 10 persons and its gross annual income does not exceed $600,000.

☐ And the business is not an affiliate of a non-small business. (Note: a non-small business employs more than 10 persons and/or its gross income exceeds $600,000.)

8. Accelerated Permitting *The Accelerated Permitting Program entitles you to install and operate qualifying sources of air pollution and abatement equipment* ***without waiting for the District to issue a Permit to Operate****. To participate in this program you must certify that your project will meet* *all* *of the following criteria. Please acknowledge each item by checking each box.*

☐ Uncontrolled emissions of any single pollutant are each less than 10 lb/highest day, or the equipment has been precertified by the BAAQMD.

☐ Emissions of toxic compounds do not exceed the trigger levels identified in Table 2-5-1 (see Regulation 2, Rule 5).

☐ The project is not subject to public notice requirements (the source is either more than 1000 ft. from the nearest school, or the source does not emit any toxic compound in Table 2-5-1).

☐ For replacement of abatement equipment, the new equipment must have an equal or greater overall abatement efficiency for all pollutants than the equipment being replaced.

☐ For alterations of existing sources, for all pollutants the alteration does not result in an increase in emissions.

☐ Payment of applicable fees (the minimum permit fee to install and operate each source). See Regulation 3 or contact the Engineering Division for help in determining your fees.

9. CEQA *Please answer the following questions pertaining to CEQA (California Environmental Quality Act).*

A. Has another public agency prepared, required preparation of, or issued a notice regarding preparation of a California Environmental Quality Act (CEQA) document (initial study, negative declaration, environmental impact report, or other CEQA document) that analyzes impacts of this project or another project of which it is a part or to which it is related? ☑YES ☐NO If no, go to section 9B.

Describe the document or notice, preparer, and date of document or expected date of completion:

CEC will perform CEQA-equivalent documentation for the proposed amendment and is expected to complete the process by May 1, 2008.

B. List and describe any other permits or agency approvals required for this project by city, regional, state or federal agencies:

Amendment to CEC license.

C. List and describe all other prior or current projects for which either of the following statements is true: (1) the project that is the subject of this application could not be undertaken without the project listed below, (2) the project listed below could not be undertaken without the project that is the subject of this application:

n/a

10. Certification *I hereby certify that all information contained herein is true and correct. (Please sign and date this form)*

GREG BOSSCAWEN	MANAGER	[signature]	12/17/07
Name of person certifying (print)	Title of person certifying	Signature of person certifying	Date

Send all application materials to the **BAAQMD Engineering Division, 939 Ellis Street, San Francisco, CA 94109.**

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station   Plant No: 18143

Emission Point No: P- 11

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 41 **S-** 42 **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 11 **A-** 12 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 220.6 sq. ft.   Height above grade: 195 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	936,640 cfm	887,192 cfm
Percent Water Vapor	9.38 Vol %	13.37 Vol %
Temperature	180 °F	180 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☑ yes ☐ no

What pollutants are monitored? NOx, CO, O2/CO2

Person completing this form Nancy Matthews   Date 11/27/07

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 12

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 43 **S-** 44 **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** 13 **A-** 14 **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 220.6 sq. ft. Height above grade: 195 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	936,640 cfm	887,192 cfm
Percent Water Vapor	9.38 Vol %	13.37 Vol %
Temperature	180 °F	180 °F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☑ yes ☐ no

What pollutants are monitored? NOx, CO, O2/CO2

Person completing this form Nancy Matthews Date 11/27/07

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station   Plant No: 18143

Emission Point No: P- 13

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 45 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 0.35 sq. ft.   Height above grade: 15 ft.

Effluent Flow from Stack

	Typical Operating Condition	***Maximum Operating Condition***
Actual Wet Gas Flowrate	1964 cfm	cfm
Percent Water Vapor	unk Vol %	Vol %
Temperature	300 °F	°F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☑ no

What pollutants are monitored? ____

Person completing this form Nancy Matthews   Date 11/27/07

DATA FORM P
Emission Point

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street .. . San Francisco, CA . . . 94109. . . (415) 749-4990 . . . Fax (415) 749-5030

Form P is for well-defined emission points such as stacks or chimneys only; do not use for windows, room vents, etc.

Business Name: Gateway Generating Station Plant No: 18143

Emission Point No: P- 18

With regard to air pollutant flow into this emission point, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 48 **S-** ____ **S-** ____ **S-** ____ **S-** ____
S- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

Exit cross-section area: 0.20 sq. ft. Height above grade: 10.67 ft.

Effluent Flow from Stack

	Typical Operating Condition	*Maximum Operating Condition*
Actual Wet Gas Flowrate	1740 cfm	cfm
Percent Water Vapor	unk Vol %	Vol %
Temperature	770 °F	°F

If this stack is equipped to measure (monitor) the emission of any air pollutants,

Is monitoring continuous? ☐ yes ☑ no

What pollutants are monitored? ____

Person completing this form Nancy Matthews Date 11/27/07

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Gateway Generating Station Plant No: 18143 Source No. S-41 (If unknown, leave blank)

2. Equipment Name & Number, or Description: natural gas-fired combustion turbine

3. Make, Model : GE 7FA Maximum firing rate: 1872 MM Btu/hr

4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*

5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated ____

6. SIC Number 4911 (If unknown leave blank)

7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☑ gas turbine
☐ other ____ ____hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ____°F
☐ liquid waste ☐ other ____ Residence time ____Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: ____
☐ open burning ☐ kiln
☐ other ____

8. Overfire air? ☐ yes ☑ no If yes, what percent ____%
9. Flue gas recirculation? ☐ yes ☑ no If yes, what percent ____%
10. Air preheat? ☐ yes ☑ no Temperature ____°F
11. Low NO_x burners? ☑ yes ☐ no Make, Model integral
12. Maximum flame temperature ____°F
13. Combustion products: Wet gas flowrate 936,640 acfm at 180 °F
Typical Oxygen Content 13.0 dry volume % or ____ wet volume % or ____ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %

16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S ____ S ____ S ____ S ____ S ____ S ____ A ____ A ____ A ____

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S 42 S ____ A 11 A 12 P 11 P ____

Person completing this form: Nancy Matthews Date: 11/27/07

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	natural gas	189	161.9E6	1872E6				
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note:
* MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

****Fuel Codes**

Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

****Basis Codes**

Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank) Source No. S-42
2. Equipment Name & Number, or Description: natural gas fired HRSG
3. Make, Model : tbd Maximum firing rate: 395 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ abatement device ☐ process heat; material heated ______ ☐ space heat ☐ cogeneration ☐ waste disposal ☐ resource recovery ☐ testing ☐ other
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other ______ ______hp

Incinerator ☐ salvage operation ☐ liquid waste ☐ pathological waste ☐ other ______ Temperature ______°F Residence time ______Sec

Others ☑ boiler ☐ afterburner ☐ flare ☐ open burning ☐ other ______ ☐ dryer ☐ oven ☐ furnace ☐ kiln Material dried, baked, or heated: ______

8. Overfire air? ☐ yes ☐ no If yes, what percent ______%
9. Flue gas recirculation? ☐ yes ☐ no If yes, what percent ______%
10. Air preheat? ☐ yes ☐ no Temperature ______°F
11. Low NO_x burners? ☐ yes ☐ no Make, Model ______
12. Maximum flame temperature ______°F
13. Combustion products: Wet gas flowrate 887,192 acfm at 180 °F (combined with CTG exhaust)
Typical Oxygen Content 11.0 dry volume % or ____ wet volume % or ____ % excess air
14. Typical Use 22.5 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 0 % Mar-May 17 % Jun-Aug 50 % Sep-Nov 33 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S 41 S ____ S ____ S ____ S ____ S ____ A ____ A ____ A ____

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S ____ S ____ A 11 A 12 P 11 P ____

Person completing this form: Nancy Matthews Date: 11/27/07

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	natural gas	189	174.5 E6	395 E6				
2.			(total, including CTG)	(HRSG only)				
3.								
4.								
5.								

Use the appropriate units for each fuel							
	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

*Use the appropriate units for each fuel: Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

***Fuel Codes**			
Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

***Basis Codes**	
Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

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Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Gateway Generating Station   Plant No: 18143   Source No. S-43 (If unknown, leave blank)
2. Equipment Name & Number, or Description: natural gas-fired combustion turbine
3. Make, Model : GE 7FA   Maximum firing rate: 1872 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☐ process heat; material heated ______
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☑ gas turbine
☐ other ______ ______hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ______°F
☐ liquid waste ☐ other ______ Residence time ______Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: ______
☐ open burning ☐ kiln
☐ other ______

8. Overfire air? ☐ yes ☑ no If yes, what percent ______%
9. Flue gas recirculation? ☐ yes ☑ no If yes, what percent ______%
10. Air preheat? ☐ yes ☑ no Temperature ______°F
11. Low NO_x burners? ☑ yes ☐ no Make, Model integral
12. Maximum flame temperature ______°F
13. Combustion products: Wet gas flowrate 936,640 acfm at 180 °F
Typical Oxygen Content 13.0 dry volume % or ______ wet volume % or ______ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S ______ **S** ______ **S** ______ **S** ______ **S** ______ **S** ______ **A** ______ **A** ______ **A** ______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S 44 **S** ______ **A** 13 **A** 14 **P** 12 **P** ______

Person completing this form: Nancy Matthews   Date: 11/27/07

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	natural gas	189	161.9E6	1872E6				
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

Fuel Codes Code	Fuel	Code	Fuel
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

Basis Codes Code	Method
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
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Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank) Source No. S-44
2. Equipment Name & Number, or Description: natural gas fired HRSG
3. Make, Model : tbd Maximum firing rate: 395 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☑ electrical generation ☐ abatement device ☐ process heat; material heated ____ ☐ space heat ☐ cogeneration ☐ waste disposal ☐ resource recovery ☐ testing ☐ other
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other ____ ____ hp

Incinerator ☐ salvage operation ☐ liquid waste ☐ pathological waste ☐ other ____ Temperature ____ °F Residence time ____ Sec

Others ☑ boiler ☐ afterburner ☐ flare ☐ open burning ☐ other ____ ☐ dryer ☐ oven ☐ furnace ☐ kiln Material dried, baked, or heated: ____

8. Overfire air? ☐ yes ☐ no If yes, what percent ____ %
9. Flue gas recirculation? ☐ yes ☐ no If yes, what percent ____ %
10. Air preheat? ☐ yes ☐ no Temperature ____ °F
11. Low NO_x burners? ☐ yes ☐ no Make, Model ____
12. Maximum flame temperature ____ °F
13. Combustion products: Wet gas flowrate 887,192 acfm at 180 °F (combined with CTG exhaust)
Typical Oxygen Content 11.0 dry volume % or ____ wet volume % or ____ % excess air
14. Typical Use 22.5 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 0 % Mar-May 17 % Jun-Aug 50 % Sep-Nov 33 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S 43 S ____ S ____ S ____ S ____ S ____ A ____ A ____ A ____

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S ____ S ____ A 13 A 14 P 12 P ____

Person completing this form: Nancy Matthews Date: 11/27/07

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	natural gas	189	174.5 E6	395 E6				
2.			(total, including CTG)	(HRSG only)				
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	*Fuel Code***	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel: *Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note: * MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

***Fuel Codes**			
Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

***Basis Codes**	
Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

(revised: 6/01)

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . fax (415) 749-5030
Website: www.baaqmd.gov

Data Form C
FUEL COMBUSTION SOURCE

(for District use only)

New ☐ Modified ☑ Retro ☐

Form C is for all operations which burn fuel except for internal combustion engines (use Form ICE unless it is a gas turbine; for gas turbines use this form). If the operation also involves evaporation of any organic solvent, complete Form S and attach to this form. If the operation involves a process which generates any other air pollutants, complete Form G and attach to this form.

☐ Check box if this source has a secondary function as an abatement device for some other source(s); complete lines 1, 2, and 7-13 on Form A (using the source number below for the Abatement Device No.) and attach to this form.

1. Company Name: Gateway Generating Station Plant No: 18143 (If unknown, leave blank) Source No. S-45
2. Equipment Name & Number, or Description: natural gas-fired dewpoint heater
3. Make, Model : GasTech Maximum firing rate: 6.5 MM Btu/hr
4. Date of modification or initial operation: 8/29/08 *(if unknown, leave blank)*
5. Primary use (check one): ☐ electrical generation ☐ space heat ☐ waste disposal ☐ testing ☐ abatement device ☐ cogeneration ☐ resource recovery ☐ other ☑ process heat; material heated natural gas fuel
6. SIC Number 4911 (If unknown leave blank)
7. Equipment type (check one)

Internal combustion Use Form ICE (Internal Combustion Engine) unless it is a gas turbine
☐ gas turbine
☐ other ____________ ________hp

Incinerator ☐ salvage operation ☐ pathological waste Temperature ______°F
☐ liquid waste ☐ other ____________ Residence time ______Sec

Others ☐ boiler ☐ dryer
☐ afterburner ☐ oven
☐ flare ☐ furnace Material dried, baked, or heated: ____________
☐ open burning ☐ kiln
☑ other natural gas fuel preheater

8. Overfire air? ☐ yes ☐ no If yes, what percent ______%
9. Flue gas recirculation? ☑ yes ☐ no If yes, what percent ______%
10. Air preheat? ☐ yes ☐ no Temperature ______°F
11. Low NO_x burners? ☐ yes ☐ no Make, Model ____________
12. Maximum flame temperature ______°F
13. Combustion products: Wet gas flowrate 1964 acfm at 300 °F
Typical Oxygen Content _____ dry volume % or _____ wet volume % or _____ % excess air
14. Typical Use 24 hours/day 7 days/week 52 weeks/year
15. Typical % of annual total: Dec-Feb 25 % Mar-May 25 % Jun-Aug 25 % Sep-Nov 25 %
16. With regard to air pollutant flow, what source(s) or abatement device(s) are immediately UPSTREAM?
S ______ S ______ S ______ S ______ S ______ S ______ A ______ A ______ A ______

With regard to air pollutant flow, what source(s) or abatement device(s), and/or emission points are immediately DOWNSTREAM?
S ______ S ______ A ______ A ______ P 13 P ______

Person completing this form: Nancy Matthews Date: 11/27/07

(revised 4/05)

FUELS

INSTRUCTIONS: Complete one line in Section A for each fuel. Section B is OPTIONAL. Please use the units at the bottom of each table. N/A means "Not Applicable."

SECTION A: FUEL DATA

	Fuel Name	*Fuel Code***	*Total Annual Usage****	*Maximum Possible Fuel Use Rate*	*Typical Heat Content*	*Sulfur Content*	*Nitrogen Content (optional)*	*Ash Content (optional)*
1.	natural gas	189	569,400	6.5 E6				
2.								
3.								
4.								
5.								

Use the appropriate units for each fuel	Natural Gas	therm*	Btu/hr	N/A	N/A	N/A	N/A
	Other Gas	MSCF*	MSCF/hr	Btu/MSCF	ppm	N/A	N/A
	Liquid	m gal*	m gal/hr	Btu/m gal	wt%	wt%	wt%
	Solid	ton	ton/hr	Btu/ton	wt%	wt%	wt%

SECTION B: EMISSION FACTORS (optional)

	Fuel Name	***Fuel Code****	**Particulates**		**NOx**		**CO**	
			Emission Factor	***Basis Code*	*Emission Factor*	***Basis Code*	*Emission Factor*	***Basis Code*
1.								
2.								
3.								
4.								

Use the appropriate units for each fuel:
*Natural Gas = lb/therm**
*Other Gas = lb/MSCF**
*Liquid = lb/m gal**
Solid = lb/ton

Note:
* MSCF = thousand standard cubic feet
* m gal = thousand gallons
* therm = 100,000 BTU
** See tables below for Fuel and Basis Codes
*** Total annual usage is: – Projected usage over next 12 months if equipment is new or modified.
– Actual usage for last 12 months if equipment is existing and unchanged.

Fuel Codes			
Code	*Fuel*	*Code*	*Fuel*
25	Anthracite coal	189	Natural Gas
33	Bagasse	234	Process gas - blast furnace
35	Bark	235	Process gas - CO
43	Bituminous coal	236	Process gas - coke oven gas
47	Brown coal	238	Process gas - RMG
242	Bunker C fuel oil	237	Process gas - other
80	Coke	242	Residual oil
89	Crude oil	495	Refuse derived fuel
98	Diesel oil	511	Landfill gas
493	Digester gas	256	Solid propellant
315	Distillate oil	466	Solid waste
392	Fuel oil #2	304	Wood - hogged
551	Gasoline	305	Wood - other
158	Jet fuel	198	Other - gaseous fuels
160	LPG	200	Other - liquid fuels
165	Lignite	203	Other - solid fuels
167	Liquid waste		
494	Municipal solid waste		

Basis Codes	
Code	*Method*
0	Not applicable for this pollutant
1	Source testing or other measurement by plant (attach copy)
2	Source testing or other measurement by BAAQMD (give date)
3	Specifications from vendor (attach copy)
4	Material balance by plant using engineering expertise and knowledge of process
5	Material balance by BAAQMD
6	Taken from AP-42 (compilation of Air Pollutant Emission Factors, EPA)
7	Taken from literature, other than AP-42 (attach copy)
8	Guess

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street, San Francisco, CA 94109
Engineering Division (415) 749-4990
www.baaqmd.gov fax (415) 749-5030

Form ICE
Internal Combustion Engines

Form ICE is to be completed for all internal combustion engines except turbines. (For turbines, submit Form C). Submit one form for each engine. If this is a new engine or a modification to an existing engine, you must also complete Form HRSA Health Risk Screen Analysis. Additional forms and all District regulations and rules are available on the District's web site. Contact your assigned permit engineer or the Engineering Division at the above telephone number if you need assistance completing this form. Please include the engine manufacturer's ***equipment specifications****.*

1. SUMMARY ☑ New Construction ☐ Modification ☐ Loss of Exemption

Company Name: Gateway Generating Station Plant No.*: 18143
Source Description: fire pump engine Source No.*: S-48
(If unknown leave blank)
Initial Date of Operation: August 2008 *(Not required for modification of an existing permitted source)*
Operating Schedule *Typical hrs/day* 1 *Days/week* 1 *Weeks/yr* 50 *Maximum hrs/day* unk

2. ENGINE INFORMATION ☐ *Check here if applying for a portable equipment permit. (See Reg. 2-1-413 for requirements)*

Engine Type: *(Check one)* ☑ 4 Stroke ☐ 2 Stroke Compression Ignition (Diesel) or ☐ 4 Stroke ☐ 2 Stroke Spark Ignition
Engine Manufacturer: John Deere Model: JW6H-UF40 Model Year: 2007
EPA/CARB Engine Family Name: 6081 Series Engine Serial No.: tbd
Engine Displacement 496 *(cu in)* Maximum rated output *(bhp)* 300 Typical load as % of bhp rating 100
Is this an emergency/standby engine? ☑ Yes ☐ No
(*Complete and check all that apply)*
Certification: ☐ EPA Certified ☑ CARB Certified CARB Executive Order No. U-R-004-0264
☐ None *(If None is checked, please indicate below the items applicable to this engine.)*
☐ Naturally aspirated ☐ Supercharged ☐ Turbocharged ☐ Inter-cooled ☐ After-cooled
☐ Timing retard ≥ 4º ☐ Lean-burn ☐ Rich-burn
Primary Use: ☐ Electrical generation ☐ Cogeneration ☐ Pump driver ☑ Fire pump driver
☐ Compressor driver ☐ Tub grinder driver ☐ Other: ______

3. ABATEMENT DEVICE INFORMATION *Complete this section only if the engine exhausts to an add-on abatement device.*
☐ *Check here if the engine has more than one add-on abatement device and complete a separate Form A for each additional abatement device.*

Abatement device number A ______ *(If unknown leave blank)* ☐ New ☐ Existing
Device type: ☐ Diesel catalyzed particulate filter ☐ Oxidation catalyst ☐ Selective catalytic reduction (SCR)
☐ Non-selective catalytic reduction (NSCR or 3-way catalyst) ☐ Other: ______
Make, Model, and Rated Capacity ______
Abatement device control efficiencies at typical operation *(Use the basis codes listed below. If unknown leave blank)*

Control Efficiency/Emission Factor Basis Codes: *(Submit supporting documentation if available)*

(1) Source testing or other measurement by plant
(2) Source testing or measurement by BAAQMD (*District use only*)
(3) Specification from vendor
(4) Material balance by plant using knowledge of process
(5) Material balance by BAAQMD (*District use only*)
(6) EPA Document AP-42 Emission Factors
(7) Taken from literature other than AP-42
(8) Guess
(9) EPA/CARB Certification

Pollutant Name	Wt % Reduction	Basis Code
Particulates		
Organics		
Nitrogen Oxides		
Sulfur Dioxide		
Carbon Monoxide		
Others – ☐ Check here and attach a separate list of pollutants. Include the basis code and the control efficiency.		

Continued on reverse side

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

Form ICE
Internal Combustion Engines

4. EMISSION POINT/STACK INFORMATION ☐ *Check here if the engine has more than one stack or has a continuous pollutant emission monitor and complete one Form P for each emission point.*

Emission point number P 18 *(If unknown leave blank)* ☑ New ☐ Existing

Stack outlet height from ground level *(ft)* 10.67

Diameter of stack outlet *(inches)* 6.065 or Outlet cross-section area *(square inches)* ______

Direction of outlet *(check one)* ☑ Horizontal ☐ Vertical End of outlet *(check one)* ☑ Open/hinged flap ☐ Rain cap

Exhaust rate at typical operation *(acfm)* 1740 Exhaust temperature at typical operation *(°F)* 770

5. RISK ASSESSMENT INFORMATION.

Distance from engine to the property line of the nearest residence *(ft)* 4200 or *(check if)* ☐ Greater than one mile

Distance from engine to the property line of the nearest school[1] *(ft)* ______ or *(check if)* ☑ Greater than 1000 ft

Describe the nearest non-residential, non-school site *(check one)* ☑ Industrial ☐ Commercial ☐ Hospital ☐ Day care center ☐ Other ______

Distance from engine to the property line of the nearest non-residential, non- school site*(ft)* 0 or ☐ Greater than one mile

1. *K-12 and more than twelve children only.*

6. FUEL DATA *Complete the table below for each fuel burned. If you are using a fuel other than those listed in the fuel code table, attach a* ***fuel analysis*** *indicating the higher heating value, sulfur content, and nitrogen content. Please clearly indicate the measurement unit that corresponds to the information you are submitting.* ☐ *Check here if you are using more than two fuels, and attach a copy of this page listing the additional fuels.*

Primary Fuel

Fuel Code[1] 98 Name CARB Diesel

Maximum Fuel Use Rate[2] 14.0 *gal/hr or SCF/hr*

Annual Fuel Usage[3] 700 *gal/yr or therm/yr or SCF/yr*

Typical Heat Content[4] 136,900 *BTU/gal or BTU/SCF*

Sulfur Content[4] 0.0015 *wt% liquids or ppmv gases*

Emission Factors *(Optional)*

Pollutant Name	Emission Factor	Units[5]	Basis Code[6]	Abated Factor (√)[7]
Particulates	0.12	g/bhp-hr	3	☐
Organics	0.29	g/bhp-hr	3	☐
Nitrogen Oxides	4.36	g/bhp-hr	3	☐
Carbon Monoxide	0.32	g/bhp-hr	3	☐

Others – ☐ Check here and attach a separate list under each fuel used.

Secondary Fuel

Fuel Code[1] ______ Name ______

Maximum Fuel Use Rate[2] ______ *gal/hr or SCF/hr*

Annual Fuel Usage[3] ______ *gal/yr or therm/yr or SCF/yr*

Typical Heat Content[4] ______ *BTU/gal or BTU/SCF*

Sulfur Content[4] ______ *wt% liquids or ppmv gases*

Emission Factors *(Optional)*

Pollutant Name	Emission Factor	Units[5]	Basis Code[6]	Abated Factor (√)[7]
Particulates				☐
Organics				☐
Nitrogen Oxides				☐
Carbon Monoxide				☐

Others – ☐ Check here and attach a separate list under each fuel used.

1. *Fuel Codes:* Diesel (**98**) Bio Diesel B100 (**815**) Bio Diesel B20 Blend (**816**) Gasoline (**551**) Natural Gas (**189**) Landfill Gas (**511**) Digester Gas (**493**) Liquid Petroleum Gas (LPG) (**160**)
2. *Maximum fuel use rate units: gallon/hr for liquid fuels and SCF/hr for gaseous fuels. (SCF =Standard Cubic Foot)*
3. *The annual fuel usage is the actual or projected engine fuel consumption over a rolling 12-month time period. Annual usage units: gallons for liquid fuel, therms for natural gas, and SCF for other gaseous fuels. (therm = 100,000 BTUs, BTU =British Thermal Unit)*
4. *If you are using diesel, natural gas, or gasoline, you may skip this entry. Heat content units: BTU/gallon for liquid fuels, BTU/SCF for gaseous fuels. Sulfur content* units: weight % for liquid fuels, ppmv for gaseous fuels. (ppmv = parts per million by volume)
5. *Emission factors may be reported as gram/brakehp-hr, or as lb per gallon, or as lb per therm, or as lb per SCF.*
6. *See the Control Efficiency/Emission Factor Basis Code table under Section 3 on page 1 of this form.*
7. *Place a check in this column if the emission factor applies to emissions* *after* *abatement by an add-on abatement device.*

7. CERTIFICATION I hereby certify that all information contained herein is true and correct. *(Please sign and date this form)*

GREG BOSSCAWEN	MANAGER	[signature]	12/17/07
Name of person certifying (print)	Title of person certifying	Signature of person certifying	Date

Approved By: ______ Date: ______ Entered By: ______ Date: ______

(District Use Only)

California Environmental Protection Agency AIR RESOURCES BOARD	DEERE POWER SYSTEMS GROUP OF DEERE & COMPANY	**EXECUTIVE ORDER U-R-004-0264** New Off-Road Compression-Ignition Engines

Pursuant to the authority vested in the Air Resources Board by Sections 43013, 43018, 43101, 43102, 43104 and 43105 of the Health and Safety Code; and

Pursuant to the authority vested in the undersigned by Sections 39515 and 39516 of the Health and Safety Code and Executive Order G-02-003;

IT IS ORDERED AND RESOLVED: That the following compression-ignition engines and emission control systems produced by the manufacturer are certified as described below for use in off-road equipment. Production engines shall be in all material respects the same as those for which certification is granted.

MODEL YEAR	ENGINE FAMILY	DISPLACEMENT (liters)	FUEL TYPE	USEFUL LIFE (hours)
2006	6JDXL08.1037	8.1	Diesel	8000

SPECIAL FEATURES & EMISSION CONTROL SYSTEMS	TYPICAL EQUIPMENT APPLICATION
Direct Diesel Injection, Turbocharger, Charge Air Cooler, Electronic Control Module, Smoke Puff Limiter	Loaders, Tractor, Pump, Compressor, Generator Set, Other Industrial Equipment

The engine models and codes are attached.

The following are the exhaust certification standards (STD), or family emission limit(s) (FEL) as applicable, and certification levels (CERT) for hydrocarbon (HC), oxides of nitrogen (NOx), or non-methane hydrocarbon plus oxides of nitrogen (NMHC+NOx), carbon monoxide (CO), and particulate matter (PM) in grams per kilowatt-hour (g/kW-hr), and the opacity-of-smoke certification standards and certification levels in percent (%) during acceleration (Accel), lugging (Lug), and the peak value from either mode (Peak) for this engine family (Title 13, California Code of Regulations, (13 CCR) Section 2423):

RATED POWER CLASS	EMISSION STANDARD CATEGORY		EXHAUST (g/kW-hr)					OPACITY (%)		
			HC	NOx	NMHC+NOx	CO	PM	ACCEL	LUG	PEAK
$130 \leq kW < 225$	Tier 3	STD	N/A	N/A	4.0	3.5	0.20	20	15	50
$225 \leq kW < 450$	Tier 3	STD	N/A	N/A	4.0	3.5	0.20	20	15	50
		FEL	-	-	6.3	-	-	-	-	-
		CERT	-	-	6.1	0.8	0.15	10	3	18

BE IT FURTHER RESOLVED: That the family emission limit(s) (FEL) is an emission level declared by the manufacturer for use in any averaging, banking and trading program and in lieu of an emission standard for certification. It serves as the applicable emission standard for determining compliance of any engine within this engine family under 13 CCR Sections 2423 and 2427.

BE IT FURTHER RESOLVED: That for the listed engine models, the manufacturer has submitted the information and materials to demonstrate certification compliance with 13 CCR Section 2424 (emission control labels), and 13 CCR Sections 2425 and 2426 (emission control system warranty).

Engines certified under this Executive Order must conform to all applicable California emission regulations.

This Executive Order is only granted to the engine family and model-year listed above. Engines in this family that are produced for any other model-year are not covered by this Executive Order.

Executed at El Monte, California on this 21st day of December 2005.

Raphael Susnowitz

for Allen Lyons, Chief
Mobile Source Operations Division

Engine Model Summary Form

Manufacturer: **John Deere Power Systems of Deere and**

Engine category: **Nonroad CI**

EPA Engine Family: **6JDXL08.1037**

amily Name: **450HF**

Process Code: **New Submission**

Attachment
U-R-004-0264

1.Engine Code	2.Engine Model	3.BHP@RPM (SAE Gross)	4.Fuel Rate: mm/stroke @ peak HP (for diesel only)	5.Fuel Rate: (lbs/hr) @ peak HP (for diesels only)	6.Torque @ RPM (SEA Gross)	7.Fuel Rate: mm/stroke@peak torque	8.Fuel Rate: (lbs/hr)@peak torque	9.Emission Control Device Per SAE J1930
6081HRW30	6081H	285.64@2100	136.50@2100	96.70@2100	1000.00@1400	188.6@1400	89.05@1400	EM EC SPL, CAC, ~~[illegible]~~, TC
6081HZ016	6081H	303.08@2100	120.30@2100	102.52@2100	976.41@1500	159.5@1500	95.24@1500	EM EC SPL
6081HDW08	6081H	199.28@2200	102.60@2200	76.13@2200	781.72@1500	151.5@1500	76.66@1500	EM EC SPL
6081HH019	6081H	300.39@2200	137.10@2200	101.72@2200	840.71@1600	165.3@1600	89.22@1600	EM EC SPL
6081HT006A	6081H	199.15@2100	99.60@2100	70.55@2100	672.57@1500	132@1500	66.80@1500	EM EC SPL
6081HT006B	6081H	217.25@2100	107.80@2100	76.42@2100	733.78@1500	145.3@1500	73.42@1500	EM EC SPL
6081HT008	6081H	261.50@2000	138.40@2000	93.30@2000	998.53@1500	196@1500	99.17@1500	EM EC SPL
6081HF070A	6081H	335.26@2200	160.00@2200	116.85@2200	1126.85@1400	226@1400	108.03@1400	EM EC SPL
6081HH027	6081H	383.54@2200	181.20@2200	134.42@2200	1087.03@1600	219@1600	118.17@1600	EM EC SPL
6081HH026	6081H	347.33@2200	162.70@2200	120.71@2200	974.93@1600	195.7@1600	105.63@1600	EM EC SPL

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143
(If unknown, leave blank)

2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 11

3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr

4. Abatement Device Code (See table*) 66 Date of Initial Operation 8/29/08

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 41 **S-** 42 **S-** ____ **S-** ____ **S-** ____ **S-** ____

A- 12 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	0	
8.	Organics	0	
9.	Nitrogen Oxides (as NO_2)	as necessary to achieve 2.0 ppm outlet	3
10.	Sulfur Dioxide	0	
11.	Carbon Monoxide	0	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** ____ **A-** ____ **A-** ____ **P-** 11 **P-** ____

Person completing this form: Nancy Matthews	Date: 11/27/07

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143
(If unknown, leave blank)

2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 12

3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr

4. Abatement Device Code (See table*) 72 Date of Initial Operation 8/29/08

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 41 **S-** 42 **S-** ______ **S-** ______ **S-** ______ **S-** ______

A- ______ **A-** ______ **A-** ______ **A-** ______ **A-** ______

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	0	
8.	Organics	as necessary to achieve 2 ppm outlet	3
9.	Nitrogen Oxides (as NO_2)	0	
10.	Sulfur Dioxide	0	
11.	Carbon Monoxide	as necessary to achieve 4 ppm outlet	3
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ______ **A-** 11 **A-** ______ **A-** ______ **P-** 11 **P-** ______

Person completing this form: Nancy Matthews Date: 11/27/07

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143
(If unknown, leave blank)

2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 13

3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr

4. Abatement Device Code (See table*) 66 Date of Initial Operation 8/29/08

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 43 **S-** 44 **S-** ____ **S-** ____ **S-** ____ **S-** ____
A- 14 **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	0	
8.	Organics	0	
9.	Nitrogen Oxides (as NO_2)	as necessary to achieve 2.0 ppm outlet	3
10.	Sulfur Dioxide	0	
11.	Carbon Monoxide	0	
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** ____ **A-** ____ **A-** ____ **P-** 12 **P-** ____

Person completing this form: Nancy Matthews Date: 11/27/07

Data Form A
ABATEMENT DEVICE

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030

for office use only

Abatement Device: Equipment/process whose primary purpose is to reduce the quantity of pollutant(s) emitted to the atmosphere.

1. Business Name: Gateway Generating Station Plant No: 18143
(If unknown, leave blank)

2. Name or Description natural gas-fired combustion turbine w/ duct firing Abatement Device No: A- 14

3. Make, Model, and Rated Capacity GE Frame 7FA, 1872 MMBtu/hr, with HRSGs, 395 MMBtu/hr

4. Abatement Device Code (See table*) 72 Date of Initial Operation 8/29/08

5. With regard to air pollutant flow into this abatement device, what sources(s) and/or abatement device(s) are **immediately** upstream?

S- 43 **S-** 44 **S-** ____ **S-** ____ **S-** ____ **S-** ____
A- ____ **A-** ____ **A-** ____ **A-** ____ **A-** ____

6. Typical gas stream temperature at inlet: TBD °F

If this form is being submitted as part of an application for an ***Authority to Construct***, completion of the following table is mandatory. If not, and the Abatement Device is *already in operation,* completion of the table is requested but not required.

	Pollutant	Weight Percent Reduction (at typical operation)	Basis Codes *(See Table**)*
7.	Particulate	0	
8.	Organics	as necessary to achieve 2 ppm outlet	3
9.	Nitrogen Oxides (as NO_2)	0	
10.	Sulfur Dioxide	0	
11.	Carbon Monoxide	as necessary to achieve 4 ppm outlet	3
12.	Other:		
13.	Other:		

14. ☐ Check box if this Abatement Device burns fuel; complete lines 1, 2 and 15-36 on Form C (using the Abatement Device No. above for the Source No.) and attach to this form.

15. With regard to air pollutant flow from this abatement device, what sources(s), abatement device(s) and/or emission point(s) are ***immediately*** downstream?

S- ____ **A-** 13 **A-** ____ **A-** ____ **P-** 12 **P-** ____

Person completing this form: Nancy Matthews	Date: 11/27/07

P:www\FormA (revised: 7/99)

Form HRSA

BAY AREA AIR QUALITY MANAGEMENT DISTRICT

939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949

WEBSITE: WWW.BAAQMD.GOV

Health Risk Screening Analysis

IMPORTANT: For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station   Plant No.: 18143

Source Description: natural gas-fired combustion turbine with HRSG

Source No.: S- 41/S-42 (if known)   Emission Point No.: P- 11 (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 195 feet OR ______ meters?

4. What is the inside diameter of the stack outlet? ______ inches OR 16.76 feet OR ______ meters

5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical

6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)

7. What is the exhaust flowrate during normal operation? 936640 cfm (cubic feet/min) OR ______ meters^3/second

8. What is the typical temperature of the exhaust gas? 180 degrees Fahrenheit OR ______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)

2. If YES (source inside building), provide building dimensions on line B1 in Section C

   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO

   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO

3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

   ____

   ____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2	please see application support					
B3	document for building details					
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

____

____

____

____

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   ☐ zoned for residential use ☐ zoned for mixed residential and commercial/industrial use
   ☑ zoned for commercial and/or industrial use ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR _______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3900 feet OR _______ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other _______________
   ____
5. Distance from source (stack or building) to property line of nearest nonresidential site = 250 feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☑ Greater than 1,000 feet
   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]
   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:
   None.
   ____

*K-12 and more than twelve children only

Form HRSA

BAY AREA AIR QUALITY MANAGEMENT DISTRICT
939 Ellis Street . . . San Francisco, CA 94109. . . (415) 749-4990 . . . FAX (415) 749-5030 OR 4949
WEBSITE: WWW.BAAQMD.GOV

Health Risk Screening Analysis

IMPORTANT: For any permit application that requires a Health Risk Screening Analysis, fill out one form for each source that emits a Toxic Air Contaminant(s) [or for a group of sources that exhaust through a common stack]. Emissions can be from a discrete point source (with stack) or a source with fugitive emissions (area or volume source). You must provide a plot plan (drawn to scale, if possible) and a local map (aerial photos are recommended), which clearly demonstrate the location of your site, the source(s), property lines, and any surrounding buildings [see attached example]. Label streets, schools, residences, and other businesses. List major dimensions of all buildings surrounding the source in Section C.

Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: natural gas-fired combustion turbine with HRSG

Source No.: S- 43/S-44 (if known) Emission Point No.: P- 12 (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 195 feet OR ______ meters?

4. What is the inside diameter of the stack outlet? ______ inches OR 16.76 feet OR ______ meters

5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical

6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)

7. What is the exhaust flowrate during normal operation? 936640 cfm (cubic feet/min) OR ______ meters^3/second

8. What is the typical temperature of the exhaust gas? 180 degrees Fahrenheit OR ______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)

2. If YES (source inside building), provide building dimensions on line B1 in Section C

   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO

   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO

3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

   ____

   ____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2	please see application support					
B3	document for building details					
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

___

___

___

___

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3700 feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other ______________
5. Distance from source (stack or building) to property line of nearest nonresidential site = 500 feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

Form HRSA

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Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: natural gas-fired dewpoint heater

Source No.: S-45 (if known) Emission Point No.: P-13 (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☑ alone OR ☐ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 15 feet OR ______ meters?
4. What is the inside diameter of the stack outlet? ______ inches OR 0.67 feet OR ______ meters
5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical
6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)
7. What is the exhaust flowrate during normal operation? 1964 cfm (cubic feet/min) OR ______ meters^3/second
8. What is the typical temperature of the exhaust gas? 300 degrees Fahrenheit OR ______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)
2. If YES (source inside building), provide building dimensions on line B1 in Section C
   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO
   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO
3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

   ____

   ____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2	please see application support					
B3	document for building details					
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 80 feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3600 feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other ______________
5. Distance from source (stack or building) to property line of nearest nonresidential site = 700 feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

Form HRSA

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Plant Name: Gateway Generating Station Plant No.: 18143

Source Description: Diesel fire pump engine

Source No.: S-48 (if known) Emission Point No.: P-18 (if known)

SECTION A *(Point Source)*

1. Does the source exhaust at clearly defined emission point; i.e., a stack or exhaust pipe? ☑ YES OR ☐ NO

   (If YES continue at #2, If NO, skip to Section B)

2. Does the stack (or exhaust pipe) stand alone or is it located on the roof of a building? ☐ alone OR ☑ on roof

   Important: If stack is on a roof, provide building dimensions on line B1 in Section C.

3. What is the height of the stack outlet above ground level? 10.67 feet OR _______ meters?

4. What is the inside diameter of the stack outlet? _______ inches OR 0.5 feet OR _______ meters

5. What is the direction of the exhaust from the stack outlet? ☑ horizontal OR ☐ vertical

6. Is the stack outlet: ☑ open or hinged rain flap OR ☐ rain capped (deflects exhaust downward or horizontally)

7. What is the exhaust flowrate during normal operation? 1740 cfm (cubic feet/min) OR _______ meters^3/second

8. What is the typical temperature of the exhaust gas? 770 degrees Fahrenheit OR _______ degrees Celsius

   (Skip Section B and Go on to Section C)

SECTION B *(Area/Volume Source)*

This section applies to fugitive emissions that are NOT captured by a collection system nor directly emitted through a stack or other emission point. Volume sources have fugitive emissions generally released within a building or other defined space (e.g., dry cleaner, gasoline station canopy). Area sources are generally flat areas of release (e.g., landfill, quarry).

1. Is the emission source located within a building? ☐ YES (go to #2) OR ☐ NO (go to #3)

2. If YES (source inside building), provide building dimensions on line B1 in Section C

   a. Does the building have a ventilation system that is vented to the outside? ☐ YES OR ☐ NO

   b. If NO (ventilation), are the building's doors & windows kept open during hours of operation? ☐ YES OR ☐ NO

3. If NO (source not inside building), provide a description of the source, dimensions, & indicate location on plot plan.

   ____

   ____

(Go on to Section C)

SECTION C *(Building Dimensions)*

Provide building dimensions. Use Line B1 only for building with source/stack on the roof or with fugitive emissions inside building. Use Lines B2-B9 for buildings surrounding the source (within 300 feet). Distance and direction are optional if map and/or aerial photo are adequately labeled with locations of buildings. Check one for units: ☐ feet OR ☐ meters

B#	Building name or description	Height	Width	Length	Distance To Source	Direction To Source
B1	Building with source:				n/a	n/a
B2	please see application support					
B3	document for building details					
B4						
B5						
B6						
B7						
B8						
B9						

NOTE: Label buildings by B# on plot plan, map and/or aerial photo. Provide comments below for any details that need additional clarification (e.g., list buildings that are co-occupied by your employees and other workers, residents, students, etc).

(Go on to Section D)

SECTION D *(Receptor Locations)*

NOTE: Indicate on maps or aerial photos the residential and nonresidential areas surrounding your facility.

1. Indicate the area where the source is located (check one):
   - ☐ zoned for residential use
   - ☐ zoned for mixed residential and commercial/industrial use
   - ☑ zoned for commercial and/or industrial use
   - ☐ zoned for agricultural use
2. Distance from source (stack or building) to nearest facility property line = 120 feet OR ______ meters
3. Distance from source (stack or building) to the property line of the nearest residence = 3600 feet OR ______ meters
4. Describe the nearest nonresidential property (check one): ☑ Industrial/Commercial OR ☐ Other ______________
5. Distance from source (stack or building) to property line of nearest nonresidential site = 1100 feet OR ______ meters
6. Distance from source to property line of nearest school* (or school site) = ______ feet OR ☑ Greater than 1,000 feet

   [Note: Helpful website with California Dept. of Education data: www.greatschools.net]

   Provide the names and addresses of all schools* that have property line(s) within 1,000 feet of the source:

   None.

*K-12 and more than twelve children only

Attachment B

Proposed Changes to the Commission Decision

Air Quality Conditions of Certification

Proposed Revisions to Air Quality Conditions of Certification
Gateway Generating Station

Pacific Gas & Electric Company is proposing the following changes to the air quality conditions of certification for the Gateway Generating Station Project. Proposed new language is shown in <u>underline</u> and deletions are shown in ~~strikeout~~.

Definitions:

1-hour period:	Any continuous 60-minute period beginning on the hour.
Calendar Day:	Any continuous 24-hour period beginning at 12:00 AM or 0000 hours.
Year:	Any consecutive twelve-month period of time
Heat Input:	All heat inputs refer to the heat input at the higher heating value fuel, in Btu/scf.
Rolling 3-hour period:	Any three-hour period that begins on the hour and does not include start-up or shutdown periods.
Firing Hours:	Period of time during which fuel is flowing to a unit, measured in fifteen-minute increments.
MM Btu:	million British thermal units
Gas Turbine Start-up Mode:	The lesser of the first ~~256~~ <u>360</u> minutes of continuous fuel flow to the Gas Turbine after fuel flow is initiated or the period of time from Gas Turbine fuel flow initiation until the Gas Turbine achieves two consecutive CEM data points in compliance with the emission concentration limits of conditions 20(b) and 20(d).
Gas Turbine Shutdown Mode:	The lesser of the ~~30~~<u>60</u> minute period immediately prior to the termination of fuel flow to the Gas Turbine or the period of time from non-compliance with any requirement listed in Conditions 20(b) and 20(d) until termination of fuel flow to the Gas Turbine.
Specified PAHs:	The polycyclic aromatic hydrocarbons listed below shall be considered to <u>be</u> 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 NOx, CO, or NH3) corrected to a standard stack gas oxygen concentration. For emission point P-11 (combined exhaust of S-41 Gas Turbine and S-42 HRSG duct burners) and emission point P-12 (combined exhaust of S-43 Gas Turbine and S-44 HRSG duct burners) the standard stack gas oxygen concentration is 15% O2 by volume on a dry basis.

Commissioning Activities: All testing, adjustment, tuning, and calibration activities recommended by the equipment manufacturers and the ~~CCPP Unit#8~~GGS 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 and is available for commercial operation~~ and has initiated sales to the power exchange~~.

Combustor Tuning Activities: All testing, adjustment, tuning, and calibration activities recommended by the gas turbine manufacturer or an independent qualified contractor to ensure safe and reliable steady state operation of the gas turbines following replacement of the combustor. This includes, but is not limited to, adjusting the amount of fuel distributed between the combustion turbine's staged fuel systems to simultaneously minimize NOx and CO production while minimizing combustor dynamics and ensuring combustor stability.

Combustor Tuning Period: The period, not to exceed 360 minutes, during which gas turbine combustor tuning activities are taking place.

Precursor Organic Compounds (POCs): Any compound of carbon, excluding methane, ethane, carbon monoxide, carbon dioxide, carbonic acid, metallic carbides or carbonates, and ammonium carbonate

CEC CPM: California Energy Commission Compliance Program Manager

~~CCPP Unit#8: Contra Costa Power Plant Unit 8~~

GGS: Gateway Generating Station

AQC-1 During construction of this facility, the following fugitive emission control measures shall be implemented at the plant site:

a. Suspend all land clearing, grading, earth moving, or excavation activities when winds (including instantaneous gusts) exceed 20 miles per hour.
b. Apply water to active construction sites and unpaved roads as frequently as necessary to control fugitive dust. The frequency of watering can be reduced or eliminated during periods of precipitation.

c. Apply sufficient water or dust suppressants to all material excavated, stockpiled, or graded to prevent fugitive dust from leaving the property boundaries and causing a public nuisance or a violation of an ambient air standard.
d. Apply a non-toxic solid stabilizer to all inactive construction areas (previously graded areas which remain inactive for 96 hours).
e. No on-site vehicle shall exceed a speed of 150 miles per hour on unpaved roads or areas.
f. All trucks hauling dirt, sand, soil, or other loose material will be watered or covered and will maintain at least two feet of freeboard to prevent a public nuisance.
g. Install wheel washers where vehicles enter and exit unpaved roads onto paved roads, or wash off trucks and any equipment leaving the site each trip.
h. At least the first 500 feet of any public roadway exiting from the construction site shall be swept at least twice daily (or less during periods of precipitation) on days when construction activity occurs or on any other day when visible soil materials are carried onto adjacent public or private paved roads.
i. Re-establish ground cover on the construction site through seeding and watering as soon as possible, but no later than final occupancy.
j. Implement all dust control measures in a timely and effective manner during all phases of project development and construction.
k. Place sandbags adjacent to roadways to prevent run off to public roadways.
l. Install wind breaks at the windward sides of construction areas prior to the soil being disturbed. The wind breaks shall remain in place until the soil is stabilized or permanently covered.
m. Provide gravel ramps of at least 20 feet in length at the tire washing/cleaning station.
n. Gravel or treat all unpaved exits from the construction site to prevent track-out to public roadways.
o. Ensure that all construction vehicles enter the construction site through the treated entrance roadways, unless an alternative route has been submitted to and approved by the CPM.
p. Sweep all paved roads within the construction site at least twice daily (or less during periods of precipitation) on days when construction activity occurs to prevent the accumulation of dirt and debris.

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

AQC-2 The project owner shall employ the following measures to mitigate, to the extent practical, construction-related emission impacts from off-road, Diesel-fired construction equipment. These measures include the use of oxidizing soot filters, oxidizing catalysts, Diesel fuel certified to CARB low sulfur fuel standards (sulfur content less than 15 ppm) and Diesel engines that are either equipped with high pressure fuel injection, employ fuel injection timing retardation or are certified to EPA Tier 2 off-road equipment emission standards. Additionally, the project owner shall restrict idle time, to the extent practical, to no more than 5 minutes.

The use of each mitigation measure is to be determined by an Air Quality Construction Mitigation Manager (AQCMM). The AQCMM is to be approved by the CPM prior to the submission of any reports. The AQCMM will determine the mitigation measures to be used within the following framework.

Construction Mitigation Framework

1. No measure or combination of measures shall be allowed to significantly delay the project construction or construction of related linear facilities.
2. No measure or combination of measures shall be allowed to cause significant damage to the construction equipment or cause a significant risk to on site workers or the public.
3. Engines certified to Tier 2 off-road equipment emission standards and CARB certified low sulfur Diesel fuel may be used in lieu of oxidizing soot filter and oxidizing catalyst.

The AQCMM will, in consultation with the California Air Resources Board (CARB), submit the following reports to the CPM for approval:

Construction Mitigation Plan

Reports of Change and Mitigation Implementation

Emergency Termination of Mitigation Reports (as necessary)

Construction Mitigation Plan

The Construction Mitigation Plan shall be submitted to the CPM for approval and will include:

1. A list of all Diesel fuel burning, off-road stationary or portable construction related equipment to be used either on the project construction site or the construction sites of the related linear facilities.
2. All construction Diesel engines, which have a rating of 100 hp or more, shall meet, at a minimum, the Tier 2 California Emission Standards for Off-Road Compression-Ignition Engines as specified in California Code of Regulations, Title 13, section 2423(b)(1) unless certified by the on-site AQCMM that such engine is not available for a particular item of equipment. In the event a Tier 2 engine is not available for any off-road engine larger than 100 hp, that item of

equipment shall be equipped with a Tier 1 engine. In the event a Tier 1 item of equipment is not available for any off-road engine larger than 100 hp, that engine shall be equipped with a catalyzed Diesel particulate filter (soot filter), unless certified by engine manufacturers or the on-site AQCMM that the use of such devices is not practical for specific engine types. For purposes of this condition, the use of such devices is “not practical” if, among other reasons:

a) There is no available soot filter that can be installed and operated in a safe and effective manner; or

b) The construction equipment is intended to be on-site for ten (10) days or less.

c) The CPM may grant relief from this requirement if the AQCMM can demonstrate that they have made a good faith effort to comply with this requirement and that compliance is not possible.

3. All heavy earthmoving equipment and heavy-duty construction related trucks with engines meeting the requirements of (2) above shall be properly maintained and the engines tuned to the engine manufacturer’s specifications.
4. All Diesel heavy construction equipment shall not remain running at idle for more than five minutes, to the extent practical.
5. The sulfur content of all Diesel fuel to be burned in any equipment used at the construction site shall be ultra-low sulfur Diesel, which contains no more than 15 ppm sulfur.

Report of Change and Mitigation Implementation
The AQCMM shall submit a Report of Change and Mitigation Implementation for approval to the CPM following the initiation of construction activities, which contains at a minimum the cause of any deviation from the Construction Mitigation Plan, and verification of the Construction Mitigation Plan measures that were implemented. Verification includes, but shall not be limited to, the following:

1. EPA or CARB engine certifications for item 2 of the Construction Mitigation Plan.
2. A copy of the contract agreement requiring subcontractors to comply with the elements under item 2 of the Construction Mitigation Plan.
3. Confirmation of the installation of either oxidizing catalysts or oxidizing soot filters as identified in items 2 and 3 of the Construction Mitigation Plan or the cause preventing the identified installations.
4. A copy of the contract agreement requiring subcontractors to comply with the elements under item 4 of the Construction Mitigation Plan.
5. A copy of receipts of purchase of Diesel fuel indicating the sulfur content as identified in item 5 of the Construction Mitigation Plan.

Emergency Termination of Mitigation Report
If a specific mitigation measure is determined to be detrimental to a piece of construction equipment or is determined to be causing significant delays in the construction schedule of the project or the associated linear facilities, the mitigation measure may be eliminated or terminated immediately. However notification must be

sent to the CPM for approval containing an explanation for the cause of the termination. All such causes are restricted to one of the following justifications and must be identified in any Emergency Termination of Mitigation Report:

1. The measure is excessively reducing normal availability of the construction equipment due to increased downtime for maintenance, and/or power output due to an excessive increase in back pressure.
2. The measure is causing or reasonably expected to cause significant damage to the construction equipment engine.
3. The measure is causing or reasonably expected to cause a significant risk to nearby workers or the public.
4. Any other seriously detrimental cause which has approval by the CPM prior to the change being implemented.

Verification: The project owner shall submit the qualifications of the AQCMM and the Construction Mitigation Plan to the CPM for approval. The project owner shall submit the Report of Change and Mitigation Implementation to the CPM for approval no later than 10 working days following the use of the specific construction equipment on either the project site or the associated linear facilities. The project owner shall submit any Emergency Termination of Mitigation Reports to the CPM for approval, as required, no later than 10 working days following the termination of any identified mitigation measure. The CPM will monitor the approval of all reports submitted by the project owner in consultation with CARB, limiting the review time for any one report to no more than 20 working days.

AQ-SC3 The wet surface air cooler (WSAC) shall be properly installed and maintained to minimize drift losses. The WSAC shall be equipped with drift eliminators with a maximum guaranteed drift rate of 0.003%. The maximum total dissolved solids (TDS) measured at the base of the WSAC or at the point of return to the wastewater facility shall not be higher than 2,500 ppmw (mg/l). The owner/operator shall sample the water at least once in the month of July, once in the month of August and once in the month of September each year while the WSAC is in operation. (PSD)

Verification: At least 30 days prior to commencement of WSAC construction, the project owner/operator shall provide to the District and CEC CPM a copy of the WSAC manufacturer's specifications demonstrating the 0.003 percent drift rate. The project owner/operator shall submit the water sample test results with the Quarterly Emissions Report required by Condition of Certification AQ-14.

AQ-SC4 The owner/operator shall perform a visual inspection of the wet surface air cooler (WSAC) 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 WSAC the owner/operator shall have the WSAC vendor's field representative inspect the drift eliminators and certify that the installation was performed in a satisfactory manner. The owner/operator shall verify that the PM10 emissions from the WSAC do not exceed 4.7 lbs/day based on the most recent total dissolved solids, measured in compliance with Condition of Certification ~~AQ-45~~AQ-SC3, and by the use of the following formula:

PM10 (lb/day) = 24 * water flow rate (lbm/hour) * design drift rate (percent) * total dissolved solids (ppm)/10^8.

Verification: The project owner/operator shall keep records of all WSAC inspections and shall make them available for the CEC CPM upon request. The project owner/operator shall report the calculated PM10 emissions from the WSAC to the CPM in the Quarterly Emissions Report required in Condition of Certification AQ-14.

Conditions for the Commissioning Period

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

Verification: The owner/operator shall submit a monthly compliance report to the California Energy Commission (CEC) Compliance Project Manager (SPM). In this report the owner/operator shall indicate how this condition is being implemented.

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

Verification: See verification in Condition AQ-1.

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

Verification: See verification in Condition AQ-1.

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

Verification: See verification in Condition AQ-1.

AQ-5 The owner/operator of the ~~CCPP Unit#8~~GGS shall submit a plan to the District Permit Services Division and the CEC CPM at least four weeks prior to first firing of S-41 or S-43 Gas Turbines describing the procedures to be followed during the commissioning of the gas turbines, HRSGs and gas-fired ~~preheater~~dewpoint heater. 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-NOx combustors, the installation and operation of the SCR systems and oxidation catalysts, the installation, calibration, and testing of the CO and NOx continuous emission monitors, and any activities requiring the firing of the Gas Turbines (S-41 & S-43) and HRSGs (S-42 & S-44) without abatement by their respective SCR and CO Catalyst Systems.

Verification: See verification in Condition AQ-1.

AQ-6 During the commissioning period, the owner/operator of the ~~CCPP Unit#8~~GGS shall demonstrate compliance with Conditions AQ-8 through 11 through the use of properly operated and maintained continuous emission monitors and data recorders for the following parameters:

1. firing hours for each gas turbine and each HRSG
2. fuel flow rates to each train
3. stack gas nitrogen oxide emission concentrations at P-11 and P-12
4. stack gas carbon monoxide emission concentrations P-11 and P-12
5. stack gas carbon dioxide or oxygen concentrations P-11 and P-12.

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

Verification: See verification in Condition AQ-1.

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

Verification: See verification in Condition AQ-1.

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

Verification: See verification in Condition AQ-1.

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

Verification: See verification in Condition AQ-1.

AQ-10 The total mass emissions of nitrogen oxides, carbon monoxide, precursor organic compounds, PM10, and sulfur dioxide that are emitted by the Gas Turbines (S-41 & S-43) and Heat Recovery Steam Generators (S-42 & S-44) during the commissioning period shall accrue towards the consecutive twelve-month emission limitations specified in condition AQ-24.

Verification: See verification in Condition AQ-1.

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

NOx (as NO2)	8,400 pounds/calendar day; 400 pounds/hour
CO	~~13,000~~40,000 pounds/calendar day; ~~584~~4,000 pounds/hour
POC(as CH4)	~~535~~1,600 pounds/calendar day
PM10	~~624~~432 pounds/calendar day
SO2	297 pounds/calendar day

Verification: See verification in Condition AQ-1.

AQ-12 Prior to the end of the Commissioning Period, the Owner/Operator shall conduct a District and CEC approved source test using external continuous emission monitors to determine compliance with Condition AQ-21. The source test shall determine NOx, CO, and POC emissions during start-up and shutdown of the gas turbines. The POC emissions shall be analyzed for methane and ethane to account for the presence of unburned natural gas. The source test shall include a minimum of three start-up and three shutdown periods. No later than twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.

Verification: Twenty working days before the execution of the source tests, the Owner/Operator shall submit to the District and the CEC Compliance Program Manager (CPM) a detailed source test plan designed to satisfy the requirements of this condition. ~~The District and the CEC CPM will notify the Owner/Operator of any necessary modifications to the plan within 20 working days of receipt of the plan; otherwise, the plan shall be deemed approved. The Owner/Operator shall incorporate the District and CEC CPM comments into the test plan. The Owner/Operator shall notify the District and the CEC CPM within seven (7) working days prior to the planned source testing date. Source test results shall be submitted to the District and the CEC CPM within 30 days of the source testing date.~~

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

AQ-13 The Gas Turbines (S-41 and S-43) and HRSG Duct Burners (S-42 and S-44) shall be fired exclusively on natural gas. (BACT for SO2 and PM10)

Verification: The project owner shall maintain, on a quarterly ~~monthly~~ basis, a laboratory analysis showing the sulfur content of natural gas being burned at the facility. The monthly sulfur analysis shall be incorporated into the quarterly compliance reports as required in Condition AQ-14 and its verification.

AQ-14 The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed ~~2,227~~ 2,094.4 MM Btu per hour, averaged over any rolling 3-hour period. (PSD for NOx)

Verification: The project owner shall prepare quarterly reports for the preceding calendar quarter by January 30, April 30, July 30, and October 30, and an annual compliance report. These reports shall incorporate all information required and specified in Condition AQ-20 and its verification. The reports shall be submitted to the District and the CEC CPM.

AQ-15 The combined heat input rate to each power train consisting of a Gas Turbine and its associated HRSG (S-41 & S-42 and S-43 & S-44) shall not exceed 49,950 MM Btu per calendar day. (PSD for PM10)

Verification: See verification in Condition AQ-14.

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

Verification: See verification in Condition AQ-14.

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

Verification: See verification in Condition AQ-14.

AQ-18 Except as provided in Condition AQ-8, S-41 Gas Turbine and S-42 HRSG shall be abated by the properly operated and properly maintained A-11 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-11 catalyst bed has reached minimum operating temperature. (BACT for NOx)

Verification: See verification in Condition AQ-14.

AQ-19 Except as provided in Condition AQ-9, S-43 Gas Turbine and S-44 HRSG shall be abated by the properly operated and properly maintained A-13 Selective Catalytic Reduction (SCR) System whenever fuel is combusted at those sources and the A-13 catalyst bed has reached minimum operating temperature. (BACT for NOx)

Verification: See verification in Condition AQ-14.

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

a. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-11 (the combined exhaust point for the S-41 Gas Turbine and the S-42 HRSG after abatement by A-11 SCR System) shall not exceed ~~20~~15.2 pounds per hour or ~~0.0090~~0.0072 lb./MM Btu (HHV) of natural gas fired. Nitrogen oxide mass emissions (calculated in accordance with District approved methods as NO2) at P-12 (the combined exhaust point for the S-43 Gas Turbine and the S-44 HRSG after abatement by A-13 SCR System) shall not exceed ~~20~~15.2 pounds per hour or ~~0.0090~~0.0072 lb./MM Btu (HHV) of natural gas fired. (PSD for NOx)

b. The nitrogen oxide emission concentration at emission points P-11 and P-12 each shall not exceed ~~2.5~~2.0 ppmv, on a dry basis, corrected to 15% O2, averaged over any 1-hour period. (BACT for NOx)

c. Carbon monoxide mass emissions at P-11 and P-12 each shall not exceed ~~0.013~~0.0088 lb./MM Btu (HHV) of natural gas fired or ~~29.22~~18.5 pounds per hour, averaged over any rolling 3-hour period. (PSD for CO)

d. The carbon monoxide emission concentration at P-11 and P-12 each shall not exceed ~~6~~4 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. (BACT for CO)

e. Ammonia (NH3) emission concentrations at P-11 and P-12 each shall not exceed ~~5~~10 ppmv, on a dry basis, corrected to 15% O2, averaged over any rolling 3-hour period. This ammonia emission concentration shall be verified by the continuous recording of the ammonia injection rate to A-11 and A-13 SCR Systems. The correlation between the gas turbine and HRSG heat input rates, A-11 and A-13 SCR System ammonia injection rates, and corresponding ammonia emission concentration at emission points P-11 and P-12 shall be determined in accordance with permit condition #29. (TRMP for NH3)

f. Precursor organic compound (POC) mass emissions (as CH4) at P-11 and P-12 each shall not exceed ~~5.6~~5.3 pounds per hour or 0.0025 lb./MM Btu of natural gas fired. (BACT)

g. Sulfur dioxide (SO_2) mass emissions at P-11 and P-12 each shall not exceed ~~6.18~~5.92 pounds per hour or 0.0028 lb./MM Btu of natural gas fired. (BACT)

h. Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed 11 pounds per hour or ~~0.00588~~0.0095 lb./MM Btu of natural gas fired when the HRSG duct burners are not in operation. Particulate matter (PM10) mass emissions at P-11 and P-12 each shall not exceed ~~13~~12 pounds per hour or ~~0.005840~~0.0065 lb./MM Btu of natural gas fired when the HRSG duct burners are in operation. (BACT)

i. Compliance with the hourly NOx emission limitations specified in condition 20(a) and 20(b) shall not be required during short-term excursions limited to a cumulative total of 10 hours per rolling 12-month period. Short-term excursions are defined as 15-minute periods designated by the owner/operator that are the direct result of transient load conditions, not to exceed four consecutive 15-minute periods, when the 15-minute average NOx concentration exceeds 2.0 ppmv, dry @ 15% O_2. Examples of transient load conditions include, but are not limited to, the following:

1. Initiation/shutdown of combustion turbine inlet air cooling
2. Rapid combustion turbine load changes
3. Initiation/shutdown of HRSG duct burners

The maximum 1-hour average NOx concentration for periods that include short-term excursions shall not exceed 30 ppmv, dry @ 15% O_2. All emissions during short-term excursions shall be included in all calculations of hourly, daily, and annual mass emission rates as required by this permit.

Verification: The project owner shall submit to the District and CEC CPM, via the quarterly reports required by condition AQ-14, the following information. In addition, this information shall be maintained on site for a minimum of five (5) years and shall be provided to District personnel on request.

a. Operating parameters of emission control equipment, including but not limited to ammonia injection rate, NOx emission rate and ammonia slip.
b. Total plant operation time (hours), number of startups, hours in cold startup, hours in warm startup, hours in hot startup, hours in shutdown, combustor tuning hours and excursion hours.
c. Date and time of the beginning and end of each startup, shutdown, combustor tuning and excursion period.
d. Average plant operation schedule (hours per day, days per week, weeks per year).
e. All continuous emissions data reduced and reported in accordance with the District approved CEMS protocol.
f. Maximum hourly, maximum daily, total quarterly, and total calendar year emissions of NOx, CO, PM10, VOC and SOx (including calculation protocol).

g. Fuel sulfur content (quarterly laboratory analyses, quarterly natural gas sulfur content reports from the natural gas supplier(s), or the results of a custom fuel monitoring schedule approved by the District.

h. A log of all excess emissions, including the information regarding malfunctions/breakdowns.

i. Any permanent changes made in the plant process or production, which would affect air pollutant emissions, and indicate when changes were made.

j. Any maintenance to any air pollutant control system (recorded on an as performed basis).

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

	Cold Start-Up or Combustor Tuning Period (lb/event)	~~Hot Start-Up (lb/event)~~	Shutdown (lb/event)
Oxides of Nitrogen (as NO2)	~~452~~600	~~189~~	~~59~~160
Carbon Monoxide (CO)	~~990~~5,400	~~291~~	~~73~~900
Precursor Organic Compounds (as CH4)	~~109~~96	~~6~~	~~6~~16

Verification: See verification in Condition AQ-20.

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

Verification: See verification in Condition AQ-20.

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

a. 1,994 pounds of NOx (as NO2) per day (CEQA)

b. ~~3,602~~11,470 pounds of CO per day (PSD)

c. 468 pounds of POC (as CH4) per day (CEQA)

d. ~~624~~577 pounds of PM10 per day (PSD)

e. 297 pounds of SO2 per day (BACT)

Verification: See verification in Condition AQ-20.

AQ-24 Cumulative combined emissions from the Gas Turbines and HRSGs (S-41, S-42, S-43, and S-44) and the ~~Fuel Gas Preheater~~Dewpoint Heater (S-45) and the ~~Cooling Tower~~ Diesel Fire Pump Engine (S-~~46~~48), including emissions generated during gas turbine start-ups, ~~and~~ shutdowns and combustor tuning periods shall not exceed the following limits during any consecutive twelve-month period:

a. 174.3 tons of NOx (as NO2) per year (Offsets, PSD)

b. ~~259.1~~555.4 tons of CO per year (Cumulative Increase)

c. 46.6 tons of POC (as CH4) per year (Offsets)

d. ~~112.2~~101.7 tons of PM10 per year (Offsets, PSD)

e. ~~48.5~~37.0 tons of SO2 per year (Cumulative Increase)

Verification: See verification in Condition AQ-20.

AQ-25 The maximum projected annual toxic air contaminant emissions (per condition 28) from the Gas Turbines and HRSGs combined (S-41, S-42, S-43, and S-44) shall not exceed the following limits:

a. ~~4,102~~12,656 pounds of formaldehyde per year

b. ~~506~~115 pounds of benzene per year

c. ~~38~~6.2 pounds of Specified polycyclic aromatic hydrocarbons (PAHs) per year

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

unless the following requirement is satisfied:

The owner/operator shall perform a health risk assessment using the emission rates determined by source test and the most current Bay Area Air Quality Management District approved procedures and unit risk factors in effect at the time of the analysis. This risk analysis shall be submitted to the District and the CEC CPM within 60 days of the source test date. The owner/operator may request that the District and the CEC CPM revise the carcinogenic compound emission limits specified above. If the owner/operator demonstrates to the satisfaction of the APCO that these revised emission limits will result in a cancer risk of not more than 10.0 in one million, the District and the CEC CPM may, at their discretion, adjust the carcinogenic compound emission limits listed above. (TRMP)

Verification: Compliance with condition AQ-28 shall be deemed as compliance with this condition. In addition, approval by the District and the CEC CPM of the reports prepared for this condition will constitute a verification of compliance with this condition.

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

a. Firing Hours and Fuel Flow Rates for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

b. Carbon Dioxide (CO_2) or Oxygen (O_2) concentrations, Nitrogen Oxides (NO_x) concentrations, and Carbon Monoxide (CO) concentrations at each of the following exhaust points: P-11 and P-12.

c. Ammonia injection rate at A-11 and A-13 SCR Systems

d. Steam injection rate at S-41 & S-43 Gas Turbine Combustors

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

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

e. Heat Input Rate for each of the following sources: S-41 & S-42 combined and S-43 & S-44 combined.

f. Corrected NO_x concentrations, NO_x mass emissions (as NO_2), corrected CO concentrations, and CO mass emissions at each of the following exhaust points: P-11 and P-12.

Applicable to emission points P-11 and P-12, the owner/operator shall record the parameters specified in conditions 26(e) and 26(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 four sources (S-41, S-42, S-43, and S-44) combined.

i. The average NO_x mass emissions (as NO_2), CO mass emissions, and corrected NO_x and CO emission concentrations for every clock hour and for every rolling 3-hour period.

j. On an hourly basis, the cumulative total NO_x mass emissions (as NO_2) and the cumulative total CO mass emissions, for each calendar day for the following: each Gas Turbine and associated HRSG combined, and all four sources (S-41, S-42, S-43, and S-44) combined.

k. For each calendar day, the average hourly Heat Input Rates, Corrected NOx emission concentrations, NOx mass emissions (as NO_2), corrected CO emission concentrations, and CO mass emissions for each Gas Turbine and associated HRSG combined.

l. On a daily basis, the cumulative total NOx mass emissions (as NO_2) and cumulative total CO mass emissions, for the previous consecutive twelve month period for all four sources (S-41, S-42, S-43, and S-44) combined.

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

Verification: At least 60 days before the initial operation, the owner/operator shall submit to the CEC CPM a plan on how the measurements and recordings required by this condition will be performed.

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

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

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

(Offsets, PSD, Cumulative Increase)

Verification: See verification in Condition AQ-20.

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

Verification: See verification in Condition AQ-20.

AQ-29 Within 60 days of start-up of the ~~CCPP Unit#8~~GGS, the owner/operator shall conduct a District-approved source test on exhaust point P-11 or P-12 to determine the corrected ammonia (NH3) emission concentration to determine compliance with condition AQ-20(e). The source test shall determine the correlation between the heat input rates of the gas turbine and associated HRSG, A-11 or A-13 SCR System ammonia injection rate, and the corresponding NH3 emission concentration at emission point P-11 or P-12. The source test shall be conducted over the expected operating range of the turbine and HRSG (including, but not limited to, minimum, 70%, 85%, and 100% load) to establish the range of ammonia injection rates necessary to achieve NOx emission reductions while maintaining ammonia slip levels. Continuing compliance with condition AQ-20(e) shall be demonstrated through calculations of corrected ammonia concentrations based upon the source test correlation and continuous records of ammonia injection rate. (TRMP)

Verification: Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests.

AQ-30 Within 60 days of start-up of the ~~CCPP Unit#8~~GGS and on an annual basis thereafter, the owner/operator shall conduct a District-approved source test on exhaust points P-11 and P-12 while each Gas Turbine and associated Heat Recovery Steam Generator are operating at maximum load ~~(including steam injection power augmentation mode)~~ to determine compliance with Conditions AQ-20(a), (b), (c), (d), (f), (g), and (h), while each Gas Turbine and associated Heat Recovery Steam Generator are operating at minimum load to determine compliance with Conditions AQ-20(c) and (d), and to verify the accuracy of the continuous emission monitors required in condition AQ-26. The owner/operator shall test for (as a minimum): water content, stack gas flow rate, oxygen concentration, precursor organic compound concentration and mass emissions, nitrogen oxide concentration and mass emissions (as NO2), carbon monoxide concentration and mass emissions, sulfur dioxide concentration and mass emissions, methane, ethane, and particulate matter (PM10) emissions including condensable particulate matter. (BACT, offsets)

Verification: Approval of the source test protocols, as required in condition AQ- 31, and the source test reports shall be deemed as verification for this condition. The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the execution of the source tests required in this condition. Source test results shall be submitted to the District and to the CEC CPM within 60 days of the date of the tests.

AQ-31 The owner/operator shall obtain approval for all source test procedures from the District's Source Test Section and the CEC CPM prior to conducting any tests. The owner/operator shall comply with all applicable testing requirements for continuous emission monitors as specified in Volume V of the District's Manual of Procedures. The owner/operator shall notify the District's Source Test Section and the CEC CPM in writing of the source test protocols and projected test dates at least 7 days prior to the testing date(s). As indicated above, the Owner/Operator shall measure the contribution of condensable PM (back half) to the total PM10 emissions. However, the Owner/Operator may propose alternative measuring techniques to measure condensable PM such as the use of a dilution tunnel or other appropriate method used to capture semi-volatile organic compounds. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the tests. (BACT)

<u>Verification:</u> Source test results shall be submitted to the District and to the CEC CPM within 60 days of the date of the tests.

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

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

<u>Verification:</u> The owner/operator shall notify the District and the CEC CPM within seven (7) working days before the owner/operator plans to conduct source testing as required by this condition. Source test results shall be submitted to the District and the CEC CPM within 60 days of conducting the test.

AQ-33 The owner/operator of the ~~CCPP Unit#8~~<u>GGS</u> 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)

<u>Verification:</u> See verification in Condition AQ-20.

AQ-34 The owner/operator of the ~~CCPP Unit#8~~GGS 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)

Verification: During site inspection, the owner/operator shall make all records and reports available to the District, ARB, EPA and CEC staffs.

AQ-35 The owner/operator of the ~~CCPP Unit#8~~GGS 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)

Verification: Submittal of these notifications as required by this condition is the verification of these permit conditions. In addition, as part of the Air Quality Reports of Condition AQ-20, the owner/operator shall include information on the dates when these violations occurred and when the owner/operator notified the District and the CEC CPM.

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

Verification: Thirty (30) days prior to start of construction, the project owner/operator shall provide the District and CEC CPM an “approved for construction” drawing showing the appropriate stack height and location of sampling ports and platforms. The project owner/operator shall make the site available to the District, EPA and CEC staff for inspection.

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

Verification: See verification of Condition AQ-36.

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

Verification: The project owner/operator shall notify the CEC CPM within 7 days of receiving the District's approval for the source testing and monitoring plan.

AQ-39 Prior to the issuance of the BAAQMD Authority to Construct for the ~~CCPP Unit#8~~GGS, the Owner/Operator shall demonstrate that valid emission reduction credits in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent (as defined by District Regulations 2-2-302.1 and 2-2-302.2), and ~~112.2~~101.7 tons of Particulate Matter less than 10 microns are under their control through enforceable contracts, option to purchase agreements, or equivalent binding legal documents. (Offsets)

Verification: Prior to the issuance of an Authority to Construct, the Owner/Operator shall provide copies of all emission reduction credits certificates to the District and the CEC CPM.

AQ-40 Prior to the start of construction of the ~~CCPP Unit#8~~GGS, the Owner/Operator shall provide to the District valid emission reduction credit banking certificates in the amount of 200.5 tons/year of Nitrogen Oxides, 53.6 tons/year of Precursor Organic Compounds or equivalent as defined by District Regulations 2-2-302.1 and 2-2-302.2 and ~~112.2~~101.7 tons of Particulate Matter less than 10 microns. (Offsets)

Verification: See verification of Condition AQ-39.

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

Verification: The owner/operator shall submit to the CEC CPM copies of the Federal (Title IV) Acid Rain and (Title V) Operating Permit within 30 days after they are issued by the District.

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

Verification: See verification of Condition AQ-41.

AQ-43 The ~~CCPP Unit#8~~<u>GGS</u> shall comply with the continuous emission monitoring requirements of 40 CFR Part 75. (Regulation 2, Rule 7)

<u>Verification:</u> At least 45 days prior to commencement of construction, the project owner/operator shall seek approval from the District for an emission monitoring plan.

AQ-44 The owner/operator shall take ~~monthly~~<u>quarterly</u> samples of the natural gas combusted at the ~~CCPP Unit#8~~<u>GGS</u>. The samples shall be analyzed for sulfur content using District- approved laboratory methods or the owner/operator shall obtain certified analytical results from the gas supplier. The sulfur content test results shall be retained on site for a minimum of five years from the test date and shall be utilized to satisfy the requirements of 40 CFR Part 60, subpart GG. Sulfur content <u>of each individual sample</u> shall be no more than 1.0 grains/100 scf. <u>Average sulfur content of four quarterly samples shall be no more than 0.75 grains/100 scf</u>. (cumulative increase)

<u>Verification:</u> See verification of Condition AQ-19.

[Conditions AQ-45 and AQ-46 should be moved to AQ-SC3 and AQ-SC4 as these units are exempt from District permitting and these conditions will be deleted from the District's permit.]

~~**AQ-45** The wet surface air cooler (WSAC) shall be properly installed and maintained to minimize drift losses. The WSAC shall be equipped with drift eliminators with a maximum guaranteed drift rate of 0.003%. The maximum total dissolved solids (TDS) measured at the base of the WSAC or at the point of return to the wastewater facility shall not be higher than 2,500 ppmw (mg/l). The owner/operator shall sample the water at least once in the month of July, once in the month of August and once in the month of September each year while the WSAC is in operation. (PSD)~~

~~**Verification:** At least 30 days prior to commencement of WSAC construction, the project owner/operator shall provide to the District and CEC CPM a copy of the WSAC manufacturer's specifications demonstrating the 0.003 percent drift rate. The project owner/operator shall submit the water sample test results with the Quarterly Emissions Report required by Condition of Certification AQ-14.~~

~~**AQ-46** The owner/operator shall perform a visual inspection of the wet surface air cooler (WSAC) 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 WSAC the owner/operator shall have the WSAC vendor's field representative inspect the drift eliminators and certify that the installation was performed in a satisfactory manner. The owner operator shall verify that the PM10 emissions from the WSAC do not exceed 4.7 lbs/day based on the most recent total~~

~~dissolved solids, measured in compliance with Condition of Certification AQ-45~~AQ-SC3~~, and by the use of the following formula:~~

~~PM10 (lb/day) = 24 * water flow rate (lbm/hour) * design drift rate (percent) * total dissolved solids (ppm)/10^8.~~

~~**Verification:** The project owner/operator shall keep records of all WSAC inspections and shall make them available for the CEC CPM upon request. The project owner/operator shall report the calculated PM10 emissions from the WSAC to the CPM in the Quarterly Emissions Report required in Condition of Certification AQ-14.~~

AQ-47 The ~~Fuel Gas Preheater~~ Dewpoint Heater (S-45) shall not be fired more than ~~192~~ 156 MMBtu/day. (BACT)

Verification: See verification of Condition AQ-20.

Conditions for S-48 Emergency Fire Pump Engine

AQ-48 Operation of S-48 for reliability-related activities is limited to 50 hours per year. (Stationary Diesel Engine ATCM)

Verification: See verification in Condition AQ-1.

AQ-49 The owner/operator shall operate engine S-48 only for the following purposes: to mitigate emergency conditions, for emission testing to demonstrate compliance with a District, state or Federal emission limit, or for reliability-related activities (maintenance and other testing, but excluding emission testing). Operating hours while mitigating emergency conditions or while emission testing to show compliance with District, state or Federal emission limits are not limited. (Stationary Diesel Engine ATCM)

Verification: See verification in Condition AQ-1.

AQ-50 The owner/operator shall operate engine S-48 only when a non-resettable totalizing meter (with a minimum display capability of 9,999 hours) that measures the hours of operation for the engine is installed, operated and properly maintained. (Stationary Diesel Engine ATCM)

Verification: See verification in Condition AQ-1.

AQ-51 Records: The owner/operator shall maintain the following monthly records in a District-approved log for at least 36 months from the date of entry. Log entries shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. (Stationary Diesel Engine ATCM)

a. Hours of operation of S-48 for reliability-related activities (maintenance and testing).

b. Hours of operation of S-48 for emission testing to show compliance with emission limits.

c. Hours of emergency operation of S-48.

d. For each emergency, the nature of the emergency condition.

e. Fuel usage for S-48.

Verification: See verification in Condition AQ-1.

Attachment C

List of Property Owners

051 031 014
Southern Energy Delta Llc
1350 Treat Blvd #500
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037 040 015
OXFOOT ASSOCIATES LLC
24737 Arnold Dr
Sonoma CA 95476

051 031 005
GAYLORD CONTAINER CORPORATION
Po Box 1149
Austin TX 78767

051 032 004
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Martinez CA 94553

051 032 007
Tony Cutino
4030 Saint Marys St
Martinez CA 94553

051 032 013
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Brentwood CA 94513

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Antioch CA 94509

051 040 044
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Po Box 7791
San Francisco CA 94120

051 040 056
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El Sobrante CA 94803

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Ei Du Pont De Nemours & Co
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Po Box 7791
San Francisco CA 94120

051 031 007
STATE OF CALIFORNIA
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San Francisco CA 94120

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051 032 009
Roy A Cunha
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051 040 009
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Antioch CA 94509

051 040 035
Wallace & Judith Gibson
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El Sobrante CA 94820

051 040 048
Linda McDaniel
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051 040 063
John E & Lillian A Whalen
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051 032 011
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051 040 019
Linda McDaniel
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051 040 064
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Fairfield CA 94534

051 040 065
SPORTSMEN INC
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051 040 066
Mechanical Co Monterey
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Oakland CA 94621

051 040 069
Trailer Storage Antioch
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American Canyon CA 94503

051 040 070
Virginia H Fleming
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Antioch CA 94509

051 040 071
Trailer Storage Antioch
2120 American Canyon Rd
American Canyon CA 94503

051 040 072
WILBUR AVENUE LLC
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051 040 073
KIEWIT CONSTRUCTION GROUP INC
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051 051 015
Norman P Jr & Edith Olsen
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051 051 018
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051 051 019
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051 051 021
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051 051 023
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051 051 024
Delta Diablo Sanitation Dist
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051 052 007
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051 052 008
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051 082 005
James Jr & Marcilynn Kennard
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