Bay Area Air Quality Management District

939 Ellis Street
San Francisco, CA 94109
(415) 771-6000

Permit Evaluation
and
Statement of Basis
For
Renewal of

MAJOR FACILITY REVIEW PERMIT

for

Calpine Gilroy Cogen, L. P. and Gilroy Energy Center, LLC
Facility #B1180

Facility Address:
1400 Pacheco Pass Highway
Gilroy, CA 95020

Mailing Address:
PO Box 1764
Gilroy, CA 95021

December, 2011

Application Engineer: Brian Lusher
Site Engineer: Brian Lusher

Application: 22569

TABLE OF CONTENTS

Title V Statement of Basis

A. Background

This facility is subject to the Operating Permit requirements of Title V of the federal Clean Air Act, Title 70 of Volume 40 of the Code of Federal Regulations (CFR), and BAAQMD Regulation 2, Rule 6, Major Facility Review because it is a major facility as defined by BAAQMD Regulation 2-6-212. It is a major facility because it has the "potential to emit," as defined by BAAQMD Regulation 2-6-218, more than 100 tons per year of a regulated air pollutant.

Major Facility Operating permits (Title V permits) must meet specifications contained in 40 CFR Part 70 as contained in BAAQMD Regulation 2, Rule 6. The permits must contain all applicable requirements (as defined in BAAQMD Regulation 2-6-202), monitoring requirements, recordkeeping requirements, and reporting requirements. The permit holders must submit reports of all monitoring at least every six months and compliance certifications at least every year.

In addition, Phase II Acid Rain facilities must meet the requirements of Title IV of the federal Clean Air Act, Acid Rain, and the Acid Rain regulations in Parts 72 through 78 of Volume 40 of the Code of Federal Regulations. These regulations were adopted and incorporated by reference by BAAQMD Regulation 2, Rule 7, Acid Rain. The main provisions of the regulations for natural gas fired acid rain sources, such as the ones at this facility, are the requirement to obtain one SO_2 allowance for each ton of SO_2 that is emitted, stringent monitoring requirements for NO_x, CO_2, and SO_2, and stringent recordkeeping and reporting.

In the Bay Area, state and District requirements are also applicable requirements and are included in the permit. These requirements can be federally enforceable or non-federally enforceable. All applicable requirements are contained in Sections I through VI of the permit.

Each facility in the Bay Area is assigned a facility identifier that consists of a letter and a 4-digit number. This identifier is also considered to be the identifier for the permit. The identifier for this facility is B1180.

This facility received its initial Title V permit on May 12, 1998. This application is for a permit renewal. Although the current permit expired on March 15, 2011, it continues in force until the District takes final action on the permit renewal. The proposed permit shows all changes to the permit in strikeout/underline format.

Pursuant to Regulation 2, Rule 6, section 416, the District has reviewed the terms and conditions of this Major Facility Review permit and determined that they are still valid and correct. This review included an analysis of all applicability determinations for all sources, including those that have been modified or permitted since the issuance of the initial Major Facility Review Permit. The review also included an assessment of the sufficiency of all monitoring for determination of compliance with applicable requirements. This statement of basis documents for permit revisions that have occurred since the initial Major Facility Review permit was issued are hereby incorporated by reference and are available upon request.

B. Facility Description

The Calpine Gilroy Cogen, LP and Gilroy Energy Center has an 87 MW gas turbine/cogeneration unit with two standby boilers and three 45 MW LM6000 gas turbines. The Calpine Gilroy Cogen supplies steam to Olam West Coast (garlic and food processing plant). The facility also has a diesel fire pump and a cooling tower.

There has been one significant change in equipment at the facility since the last renewal on March 16, 2006. S-100 has been retrofitted with Dry Low NO_x combustors and no longer uses steam injection for NO_x control. The combustors were installed and partially commissioned during May and June of 2011. The commissioning of the combustors is scheduled to be completed by December 31, 2011. S-100 will meet a NO_x limit of 5 ppm @ 15%O_2 during normal operation by January 1, 2012. Previously, S-100 was required to meet a NO_x limit of 21 ppm @ 15%O_2 during normal operation.

The emissions from the facility have varied according to the peak power demands of the region and the steam production demand from the adjacent garlic and food processing plant. The District records contain the following emission summaries by year:

Year	NOx (tons/year)	CO (tons/year)	POC (tons/year)	PM10 (tons/year)	SOx (tons/year)
2006	75.2	14.6	3.2	5.6	0.5
2007	69.5	14.6	2.8	5.3	0.5
2008	69.6	14.6	2.8	5.3	0.5
2009	96.4	20.6	4.1	6.75[a]	0.7
2010	89.2	29.6	6.1	7.28[a]	0.9
2011	59.6	18.1	4.1	5.32[a]	0.6

[a] PM10 emissions from the cooling tower were updated with a revised emission factor and throughput values. The cooling tower emission factor was changed after 2008 to an erroneous value. The cooling tower throughput data also had errors after 2008.

The applications processed by the District since the last renewal (3/16/06) are:

Application No. 12918 (3/16/06) NSR Application to incorporate changes to Condition No. 18102. The firing rate was increased for S-3, S-4, and S-5. The sulfur content limit was increased from 0.25 gr/100 scf to 1 gr/100 scf. The ammonia slip monitoring condition was revised. The source test frequency was revised from annual to once every 8,000 hours of operation or three years whichever occurs first. Finally, the fuel gas analysis frequency was updated.

Application No. 6748 (3/16/06) Title V Renewal

Application No. 12390 (9/17/07) Title V minor revision to incorporate changes related to NSR Application No. 12918.

Application No. 18434 (12/22/10) NSR Application to install dry Low NOx combustors on S-100 to meet Regulation 9, Rule 9 requirements.

Application No. 22302 (3/9/11) Title V Application to incorporate the installation of dry Low NOx combustors on S-100 into Title V permit.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order presented in the permit.

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. If the Title IV (Acid Rain) requirements for fossil-fuel fired electrical generating facilities or the accidental release (40 CFR § 68) programs apply, the section will contain a standard condition pertaining to these programs. Many of these conditions derive from 40 CFR § 70.6, Permit Content, which dictates certain standard conditions that must be placed in the permit. The language that the District has developed for many of these requirements has been adopted into the BAAQMD Manual of Procedures, Volume II, Part 3, Section 4, and therefore must appear in the permit.

The standard conditions also contain references to BAAQMD Regulation 1 and Regulation 2. These are the District's General Provisions and Permitting rules.

The dates of adoption and approval of the following rules in Standard Condition 1.A have been updated.

- Regulation 2, Rule 5 – New Source Review of Toxic Air Contaminants
- Regulation 2, Rule 6 - Permits, Major Facility Review have been added to Standard Condition 1.A.

The following language was added as Standard Condition I.B.12: "The permit holder is responsible for compliance, and certification of compliance, with all conditions of the permit, regardless whether it acts through employees, agents, contractors, or subcontractors. (Regulation 2-6-307)." The purpose is to reiterate that the Permit Holder is responsible for ensuring that all activities at the facility comply with all applicable requirements.

The Standard Condition I.K. has been revised to reflect that 40 CFR Part 68 Chemical Accident Prevention Provisions do not apply to the facility. The ammonia concentration in abatement device A-4, A-6, and A-8 is less than 20% by weight.

II. Equipment

This section of the permit lists all permitted or significant sources. Each source is identified by an S and a number (e.g., S24).

The proposed Renewal Application required minor changes to this section of the permit. The combustion equipment firing rates contained in Table 2 were revised to be on a higher heating value (HHV) basis in units of MMBtu/hour. The source description for S-100 was revised to reflect the installation of dry Low NO_x combustors (steam injection is no longer used for NO_x control).

III. Generally Applicable Requirements

This section of the permit lists requirements that generally apply to all sources at a facility including insignificant sources and portable equipment that may not require a District permit

The following language was added to this section:

> "Unpermitted sources are exempt from normal District permits pursuant to an exemption in BAAQMD Regulation 2, Rule 1. They may, however, be specifically described in a Title V permit if they are considered significant sources pursuant to the definition in BAAQMD Rule 2-6-239."

> "Portable equipment operating in accordance with the ARB portable equipment registration program and temporary equipment such as sandblasting equipment may be operated at the facility as long as the source is not significant under Rule 2-6-239. Otherwise significant source would need to be included in the Title V permit."

Table III Generally Applicable Requirements was revised to change the effectiveness dates of applicable District Rules and Regulations and to add new applicable requirements to the facility as shown below:

Action	Title/Description
Revised Effective Dates for BAAQMD Rules and Regulations. Verified federal enforceability status for each requirement listed in Table III.	
Added, SIP Version of Regulation 2-1-429	Federal Emissions Statement
Added, BAAQMD Regulation 2, Rule 2	Permits, New Source Review
Added, SIP Regulation 2, Rule 2	Permits, New Source Review
Added, BAAQMD Regulation 2, Rule 3	Power Plants
Added, BAAQMD Regulation 2, Rule 4	Permits, Emissions Banking
Added, SIP Regulation 2, Rule 4	Permits, Emissions Banking
Added, BAAQMD Regulation 2, Rule 5	New Source Review of Toxic Air Contaminants (6/15/05)
Added, BAAQMD Regulation 2, Rule 6	Permits, Major Facility Review
Added, SIP Regulation 2, Rule 6	Permits, Major Facility Review
Added, BAAQMD Regulation 2, Rule 9	Permits, Interchangeable Emission Reduction Credits
Added, BAAQMD Regulation 3	Fees
Added BAAQMD Regulation 5	Open Burning
Added SIP Regulation 5	Open Burning
Added, BAAQMD Regulation 6, Rule 1	Particulate Matter and Visible Emissions
Added, SIP Regulation 6	Particulate Matter and Visible Emissions
Added, BAAQMD Regulation 8, Rule 2	Organic Compounds – Miscellaneous Operations
Added SIP Regulation 8, Rule 2	Organic Compounds – Miscellaneous Operations
Added, BAAQMD Regulation 8, Rule 4	General Solvent and Surface Coating
Added, BAAQMD Regulation 8, Rule 15	Organic Compounds – Emulsified and Liquid Asphalts
Added, SIP Regulation 8, Rule 40	Organic Compounds – Aeration of Contaminated Soil and Removal of Underground Storage Tanks
Added, SIP Regulation 8, Rule 47	Organic Compounds – Air Stripping and Soil Vapor Extraction Operations
Added SIP Regulation 8, Rule 51	Adhesive and Sealant Products
Added BAAQMD Regulation 9, Rule 9	Nitrogen Oxides and Carbon Monoxide from Stationary Gas Turbines
Added SIP Regulation 9, Rule 9	Nitrogen Oxides from Stationary Gas Turbines
Added, California Health and Safety Code Section 93115 et seq.,	Airborne Toxic Control Measure for Stationary Compression Ignition Engines
Added, California Health and Safety Code Title 17, Section 93116	Airborne Toxic Control Measure for Diesel Particulate Matter from Portable Engines Rated at 50 Horsepower and Greater
Added 40 CFR Part 60, Subpart GG	Standards of Performance for Stationary Gas Turbines (2/24/06)
Added 40 CFR Part 60, Subpart KKKK	Standards of Performance for Stationary Combustion Turbines (7/6/06)

Action	Title/Description
Added, 40 CFR Part 61, Subpart M	NESHAPS – National Emissions Standard for Asbestos
Added, 40 CFR Part 82	Protection of Stratospheric Ozone

The facility periodically may send one of the peaking gas turbines (S-3, S-4, S-5) out for offsite maintenance. When this occurs a temporary gas turbine is often brought in to replace the turbine sent offsite for maintenance. The temporary gas turbine is considered a new source and is subject to applicable portions of the following:

- District Regulation 2, Rule 1
- District Regulation 2, Rule 2
- District Regulation 9, Rule 9
- 40 CFR Part 60, Subpart GG
- 40 CFR Part 60, Subpart KKKK

The District has added these regulations to Table III of the Title V permit.

IV. Source-Specific Applicable Requirements

This section of the permit lists the applicable requirements that apply to permitted or significant sources. These applicable requirements are contained in tables that pertain to one or more sources that have the same requirements. The order of the requirements is:

- District Rules
- SIP Rules (if any) are listed following the corresponding District rules. SIP rules are District rules that have been approved by EPA for inclusion in the California State Implementation Plan. SIP rules are “federally enforceable” and a “Y” (yes) indication will appear in the “Federally Enforceable” column. If the SIP rule is the current District rule, separate citation of the SIP rule is not necessary and the “Federally Enforceable” column will have a “Y” for “yes”. If the SIP rule is not the current District rule, the SIP rule or the necessary portion of the SIP rule is cited separately after the District rule. The SIP portion will be federally enforceable; the non-SIP version will not be federally enforceable, unless EPA has approved it through another program.
- Other District requirements, such as the Manual of Procedures, as appropriate.
- Federal requirements (other than SIP provisions)
- BAAQMD permit conditions. The text of BAAQMD permit conditions is found in Section VI of the permit.
- Federal permit conditions. The text of Federal permit conditions, if any, is found in Section VI of the permit.

Some notable applicability determinations regarding sources at the facility are as follows:

- <u>Accidental Release</u>
  Ammonia storage at this facility is not subject to 40 CFR 68, Accidental Release, because aqueous ammonia used by the Selective Catalytic Reduction units has a concentration of less than 20% by weight.

- <u>112(j)</u>
  The facility is not subject to the case-by-case MACT determination requirement in 112(j) of the Clean Air Act because it is not a major facility for hazardous air pollutants (HAPs). The facility does not emit 10 tons/year of any single HAP or 25 tons/year of aggregate HAP. The facility wide potential to emit for HAPs is shown in the Table below. Detailed calculations are attached in Appendix C. Note that ammonia, propylene, and sulfuric acid mist are not HAPs pursuant to 112(b) of the Clean Air Act. Therefore, 40 CFR 63, Subpart YYYY, NESHAP for Stationary Combustion Turbines does not apply to S-3, S-4, S-5, and S-100.

Toxic Air Contaminant	Facility (lb/hour)	Facility (lb/year)	Acute Risk Screening Trigger Level (lb/hr)	Chronic Risk Screening Trigger Level (lb/yr)	Facility (ton/year)	Description
1,3-Butadiene	3.22E-04	1.87E+00	None	6.30E-01	9.34E-04	
Acetaldehyde	3.47E-01	2.01E+03	None	3.80E+00	1.01E+00	
Acrolein	4.79E-02	2.78E+02	5.50E-03	1.40E+01	1.39E-01	
Ammonia	2.10E+01	7.69E+04	7.10E+00	7.70E+03	3.85E+01	not a HAP
Benzene	3.41E-02	1.96E+02	2.90E+00	3.80E+00	9.82E-02	
Benzo(a)anthracene	5.73E-05	3.32E-01	None	None	1.66E-04	*included in Specified PAHs*
Benzo(a)pyrene	3.52E-05	2.04E-01	None	6.90E-03	1.02E-04	*included in Specified PAHs*
Benzo(b)fluoranthene	2.86E-05	1.66E-01	None	None	8.31E-05	*included in Specified PAHs*
Benzo(k)fluoranthene	2.79E-05	1.62E-01	None	None	8.09E-05	*included in Specified PAHs*
Chrysene	6.39E-05	3.71E-01	None	None	1.85E-04	*included in Specified PAHs*
Dibenz(a,h)anthracene	5.96E-05	3.46E-01	None	None	1.73E-04	*included in Specified PAHs*
Ethylbenzene	4.54E-02	2.63E+02	None	4.30E+01	1.32E-01	
Formaldehyde	1.18E+00	6.78E+03	1.20E-01	1.80E+01	3.39E+00	
Hexane	6.56E-01	3.81E+03	None	2.70E+05	1.90E+00	
Indeno(1,2,3-cd)pyrene	5.96E-05	3.46E-01	None	None	1.73E-04	*included in Specified PAHs*
Naphthalene	4.21E-03	2.44E+01	None	None	1.22E-02	
Propylene	1.95E+00	1.13E+04	None	1.20E+05	5.67E+00	not a HAP
Propylene Oxide	1.21E-01	7.03E+02	6.80E+00	2.90E+01	3.51E-01	
Toluene	1.81E-01	1.05E+03	8.20E+01	1.20E+04	5.23E-01	
Xylene (Total)	6.61E-02	3.84E+02	4.90E+01	2.70E+04	1.92E-01	
Sulfuric Acid Mist (H2SO4)	1.73E+00	6.86E+03	2.60E-01	3.90E+01	3.43E+00	not a HAP
Benzo(a)pyrene equivalents	1.16E-04	6.72E-01	None	6.90E-03	3.36E-04	*included in Specified PAHs*
Specified PAHs	3.32E-04	1.93E+00	None	None	9.63E-04	
Total HAPs					7.750	
Total Toxic Air Contaminants and HAPs					55.31	

- <u>Compliance Assurance Monitoring (CAM) – 40 CFR Part 64</u>

  The gas turbines (S-3, S-4, S-5 and S-100) are exempt from CAM requirements for NO_x per 40 CFR Part 64.2(b)(iii) since the facility is subject to the acid rain permit program. The facility is subject to the Acid Rain program because it is a utility unit that serves a generator with a capacity than 25 MW in accordance with 40 CFR Part 72.6. Per 40 CFR 64.2(a), an emission unit is subject to 40 CFR 64, Compliance Assurance Monitoring, if the unit is subject to a federally enforceable requirement for a pollutant, the pollutant is controlled by an abatement device, and the emissions of the pollutant before abatement are more than 100% of the major source thresholds.

An analysis of the carbon monoxide (CO) emissions from each gas turbine (S-3, S-4, S-5, S-100) has been prepared by the District and is shown below. The basis for the CO potential to emit calculation assumes the 6 ppmv @ 15% O_2 permit limit.

S-3, S-4, S-5 CO Potential to Emit

Permit Condition No. 18102 Part 22 limits annual CO emissions from S-3, S-4, and S-5 combined to 36 tons/year.

S-100 CO Potential to Emit

Permit Condition No. 2780 Part 3b limits CO emissions from S-100, S-101, and S-102 combined to less than 100 tons/year.

The potential to emit for each of the gas turbines (S-3, S-4, S-5, S-100) is less than 100 tons/year each for CO. The CO emissions from each simple cycle gas turbine (S-3, S-4, S-5) are not subject to CAM requirements.

The CO potential to emit for S-100 is less than 100 tons/year. The CO emissions from the combined cycle gas turbine S-100 are not subject to CAM requirements since the CO monitor was installed and included in the initial Title V operating permit application (issued on 5/12/98, completeness date before 10/22/97) prior to the CAM regulation being promulgated (10/22/97). The CO CEM installed on S-100 meets the exemption requirements contained in 40 CFR Part 64(b)(vi) and therefore S-100 is not subject to CAM requirements.

The preabatement potential to emit for each boiler is less than 100 tons/year each for NO_x and CO. The NO_x preabatement potential to emit was estimated at 100 ppm NO_x which is equal to 0.121 lb/MMBtu @ 3% O_2. NO_x potential to emit equals 911,040 MMBtu/year x 0.121 lb/MMBtu x ton/2000 lb = 55.1 tons/year. The CO potential to emit was estimated at 50 ppm CO @ 3% O_2 which is equal to 0.0368 lb/MMBtu @ 3% O_2. CO potential to emit equals 911,040 MMBtu/year x 0.0368 lb/MMBtu x ton/2000 lb = 16.8 tons/year. CO emissions from the auxiliary boilers S-101 and S-102 are exempt from CAM requirements since the preabatement potential to emit is less than 100 tons/year and these units are not abated by a CO oxidation catalyst (See 64.2(a)).

Changes to permit (S-3, S-4, S-5):

Section IV of the permit contains citations to all of the applicable requirements for particular sources. The text of the requirements is found in the regulations, which are readily available on the District's or EPA's websites, or in the permit conditions, which are found in Section VI of the permit. All monitoring requirements are cited in Section IV. Section VII is a cross-reference between the limits and monitoring requirements. A discussion of monitoring is included in Section C.VII of this permit evaluation/statement of basis.

Table IV Source Specific Applicable Requirements were revised to change the effectiveness dates of applicable District Rules and Regulations and to add new applicable requirements to the gas turbines (S-3, S-4, and S-5) in Table IV-A as shown below:

Action	Title/Description
Added BAAQMD Regulation 6-1-301	Ringlemann Number 1 Limitation to Table IV-A for the gas turbines.
Added BAAQMD Regulation 6-1-305	Visible Particles to Table IV-A for the gas turbines.
Added BAAQMD Regulation 6-1-310	Particulate Weight Limitation to Table IV-A for the gas turbines.
Added BAAQMD Regulation 6-1-401	Appearance of Emissions to Table IV-A for the gas turbines
Added SIP Versions of Regulation 6	Particulate Emissions General Requirements
Added BAAQMD Regulation 9-9-113	Exemption – Inspection and Maintenance
Added BAAQMD Regulation 9-9-114	Exemption – Startup/Shutdown
Added BAAQMD Regulation 9-9-301.1.3	Emission Limits Turbines Rated ≥ 10 MW with SCR to Table IV-A for the gas turbines
Added BAAQMD Regulation 9-9-301.2	Emission Limits General to Table IV-A for the gas turbines
Added BAAQMD Regulation 9-9-401	Certification, Efficiency to Table IV-A for the gas turbines
Added BAAQMD Regulation 9-9-501	Monitoring and recordkeeping requirements
Added SIP Versions of Regulation 9, Rule 9 to Table IV-A for the gas turbines	Nitrogen Oxide Emissions from Stationary Gas Turbines
Updated 40 CFR 60 Subpart A	NSPS – General Provisions
Updated regulatory citations for 40 CFR Part 60 Subpart GG in Table IV-A for the gas turbines (Including BAAQMD Regulation 10)	New Source Performance Standards for Gas Turbines
Added 40 CFR Part 72 Requirements	Acid Rain Program
Added 40 CFR Part 75 Requirements	Continuous Emission Monitoring for Acid Rain Sources

40 CFR Part 60, Subpart GG

60.332(a)(1) has a NO_x limit of nominally 75 ppm. The emissions units (S-3, S-4 and S-5) meet a permit limit of 5 ppm @ 15 % O_2 and therefore comply with the Subpart GG NO_x limit.

Section 60.333(a) requires an owner/operator of stationary turbines to demonstrate compliance with either one of the following two conditions:

- Discharge SO_2 at less than or equal to 0.015% by volume at 15% oxygen on a dry basis <u>or</u>
- Combust fuel with sulfur content less than or equal to 0.8% by weight (8000 ppmw).

The typical annual average sulfur concentration of the PUC quality natural gas combusted in the turbines is 0.25 grains/100 scf. PG&E natural gas typically has a sulfur concentration of 1 grain/100 scf (See PG&E Gas Rule 21, Section C). The SO_2 content in the natural gas can be compared to Section 60.333(a) as follows:

lb S/MMBtu = 1 grains/100 scf x lb/7000 grains x scf/1020 Btu x 1 E06 Btu/MMBtu

lb S/MMBtu = 1.4 E-03

lb SO_2/MMBtu = 1.4 E-03 lb/MMBtu x (64 lb SO_2/lb-mol/32 lb S/lb-mol)

lb SO_2/MMBtu = 2.8 E-03

<u>Gas Turbines</u>

SO_2 lb/hour = 2.8 E-03 lb/MMBtu x 500 MMBtu/hour = 1.4

SO_2 ppm = (1.4 lb/hour x 1/64 lb/lb-mol x 386.8 scf/lb-mol)/(8710 dscf/MMBtu x 500 MMBtu/hour x (20.95/(20.95 – 15)) x 1 E06

SO_2 ppm = 0.6 ppm @ 15% O_2

The calculations demonstrate that the gas turbines at the facility meet Section 60.333(a). After the February 24, 2006 revisions to 40 CFR Part 60 Subpart GG the facility is no longer required to monitor the sulfur content of the fuel to be in compliance with this NSPS (See 40 CFR 60.334(h)(3)).

40 CFR Part 72, Acid Rain Program

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The gas turbines (S-3, S-4, S-5) are affected utility units subject to the program in accordance with 40 CFR, Part 72, Subpart A, Section 72.6(a)(3)(i). The facility continues to meet 72.9 Standard Requirements which requires the submission of a complete acid rain permit application, the possession of a valid acid rain permit, meeting the monitoring requirements of part 75, and holding sufficient allowances, and comply with the acid rain SO_2 limit. The facility must hold sufficient SO_2 allowances by March 1 (February 29 of a leap year) of every year to offset each ton of SO_2 emitted for the previous calendar year. The facility is expected to comply with the excess emissions, recordkeeping and reporting requirements in 72.9(e) and 72.9(f).

Part 72, Subpart C, contains requirements for acid rain permit applications and compliance plans. The facility is expected to continue to meet these requirements.

Part 72, Subpart E, contains the requirements for the acid rain permit which must include all elements of a complete acid rain application.

40 CFR Part 75, Continuous Emission Monitoring

Part 75, Subpart A, contains the applicability criteria, compliance dates, and prohibitions. The emissions units at the facility are subject to Part 72 and are therefore subject to Part 75. The NO_x monitoring is subject to part 75 per 75.2(c). The facility is expected to continue to meet the compliance dates and prohibitions contained in part 75 Subpart A.

Part 75, Subpart B, contains specific monitoring provisions for each pollutant subject to part 75. The emissions units at this facility are required to meet the SO_2, NO_x, CO_2 monitoring requirements contained in 75.10(a)(1), 75.10(a)(2), 75.10(a)(3) Opacity monitoring under 75.10(a)(4) is not required for gas fired units in accordance with 75.14(c). 75.10(b) requires each CEM to meet equipment, installation, and performance specification in part 75 Appendix A and quality assurance/quality control in Appendix B. 75.10(c) requires heat input rate monitoring to meet requirements contained in part 75 Appendix F. The facility is expected to continue to comply with the requirements contained in 75.10(b) and (c).

75.10(d) contains primary equipment hourly operating requirements that require the CEM to monitor emissions when the emissions unit combusts fuel except as specified in 75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §75.20. This section also contains requirements for calculating hourly averages from four 15-minute periods and validity of data and data substitution. Emission concentrations for a given hour are not considered valid unless it is based on four valid measurements. The data substitution requirements are contained in Subpart D. The facility is expected to continue to comply with the requirements contained in 75.10(d). 75.10(f) specifies minimum measurement capability requirement for CEMs and 75.10(g) contains the minimum recordkeeping and reporting requirements. The facility is expected to continue to meet 75.10(f) and (g).

75.11 contains specific provisions for SO_2 monitoring. 75.11(d)(2) allows the use of Appendix D to monitor SO_2 emissions from gas fired units. The facility monitors sulfur content of the natural gas to meet Part 75 SO_2 monitoring requirements.

75.12 contains specific provisions for NO_x emission rates. The facility uses a NO_x CEM and an O_2 monitor to meet this requirement.

75.13 contains CO_2 monitoring requirements. The facility monitors CO_2 in accordance with this section using the procedures in part 75 Appendix G.

75.14 contains opacity monitoring requirements. The facility is exempt from opacity monitoring under part 75 per 75.14(c).

Part 75 Subpart C contains operation and maintenance requirements including certification and recertification of the CEMs, quality assurance/quality control requirements, reference test methods, and out-of-control periods and adjustment for system bias. The facility is expected to continue to meet these requirements.

Part 75, Subpart D (75.30 through 75.36) contains Missing Data Substitution Procedures for SO_2, NO_x, flowrate, CO_2, and heat input procedures. The facility is expected to continue to meet these requirements.

Part 75, Subpart F contains the recordkeeping requirements including the contents of a part 75 monitoring plan. This subpart requires the facility to record the operating time, heat input rate, and load for each emissions unit. Additionally, the facility must record emissions data for SO_2, NO_x, CO_2, and O_2 along with quality assurance/quality control information.

Part 75, Subpart G contains the reporting requirements for affected facilities subject to part 75. The facility is expected to continue to meet these requirements.

Changes to permit (S-100):

Table IV Source Specific Applicable Requirements were revised to change the effectiveness dates of applicable District Rules and Regulations and to add new applicable requirements to the gas turbine (S-100) in Table IV-B as shown below:

Action	Title/Description
Added BAAQMD Regulation 6-1-301	Ringlemann Number 1 Limitation to Table IV-A for the gas turbine.
Added BAAQMD Regulation 6-1-305	Visible Particles to Table IV-A for the gas turbines.
Added BAAQMD Regulation 6-1-310.3	Particulate Weight Limitation to Table IV-A for the gas turbines.
Added BAAQMD Regulation 6-1-401	Appearance of Emissions to Table IV-A for the gas turbines
Added SIP Versions of Regulation 6	Particulate Emissions General Requirements
Added BAAQMD Regulation 9-9-113	Exemption – Inspection/Maintenance
Added BAAQMD Regulation 9-9-114	Exemption – Start Up/Shutdown
Added BAAQMD Regulation 9-9-301	Emission Limits - General
Added BAAQMD Regulation 9-9-301.1.2	Emission Limits Turbines Rated ≥ 10 MW without SCR to Table IV-B for the gas turbine
Added BAAQMD Regulation 9-9-301.2	Emission Limits General to Table IV-B for the gas turbine
Added BAAQMD Regulation 9-9-401	Certification, Efficiency to Table IV-B for the gas turbine
Added BAAQMD Regulation 9-9-402.2	Compliance Schedule
Added BAAQMD Regulation 9-9-501	Monitoring and recordkeeping requirements
Added SIP Versions of Regulation 9, Rule 9	Nitrogen Oxide Emissions from Stationary Gas Turbine
Updated 40 CFR 60 Subpart A	NSPS – General Provisions
Updated regulatory citations for 40 CFR Part 60 Subpart GG	New Source Performance Standards for Gas Turbine
Added 40 CFR Part 72 Requirements	Acid Rain Program
Added 40 CFR Part 75 Requirements	Continuous Emission Monitoring for Acid Rain Sources
Made changes to Condition No. 2780 reflecting that fact that the facility has installed Dry Low NO_x combustors (DLN) on S-100. DLN operational on May 25, 2011.	
Made changes to Condition No. 21961 reflecting the fact that the facility has installed Dry Low NO_x combustors on S-100. DLN operational on May 25, 2011.	

BAAQMD Regulation 9, Rule 9, Section 301.2

The emission standards of this section were effective January 1, 2010 for most gas turbines in the District. Regulation 9, Rule 9, Section 402.2 allows a gas turbine to comply with Section 301.2 after the end of the next major maintenance outage, but in no event later than January 1, 2012.

Calpine installed new dry Low NO_x combustors to meet Regulation 9, Rule 9 requirements in May of 2011 as allowed by the rule. The Dry Low NO_x combustors have been partially commissioned in May and June of 2011 and demonstrated that S-100 can comply with the 5 ppm NOx limit in Section 301.2, but the gas turbine has not been able to operate at its rated capacity with the new combustors installed. The facility and the gas turbine vendor are working on the turbine capacity issue. The remaining commissioning activities are scheduled to be completed by December 31, 2011. S-100 will be required to meet the NO_x limits contained in Section 301.2 by the end of the combustor commissioning or January 1, 2012 at the latest.

40 CFR Part 60, Subpart GG

60.332(a)(1) has a NO_x limit of nominally 75 ppm. The emissions unit (S-100) meets a permit limit of 5 ppm @ 15 % O_2 and therefore complies with the Subpart GG NO_x limit.

Section 60.333(a) requires an owner/operator of stationary turbines to demonstrate compliance with either one of the following two conditions:

- Discharge SO_2 at less than or equal to 0.015% by volume at 15% oxygen on a dry basis <u>or</u>
- Combust fuel with sulfur content less than or equal to 0.8% by weight (8000 ppmw).

The typical annual average sulfur concentration of the PUC quality natural gas combusted in the turbine is 0.25 grains/100 scf. PG&E natural gas typically has a sulfur concentration of 1 grain/100 scf (See PG&E Gas Rule 21, Section C). The SO_2 content in the natural gas can be compared to Section 60.333(a) as follows:

lb S/MMBtu = 1 grains/100 scf x lb/7000 grains x scf/1020 Btu x 1 E06 Btu/MMBtu

lb S/MMBtu = 1.4 E-03

lb SO_2/MMBtu = 1.4 E-03 lb/MMBtu x (64 lb SO_2/lb-mol/32 lb S/lb-mol)

lb SO_2/MMBtu = 2.8 E-03

<u>Gas Turbine and Heat Recovery Steam Generator</u>

SO_2 lb/hour = 2.8 E-03 lb/MMBtu x 1085 MMBtu/hour = 3.04

SO_2 ppm = (3.04 lb/hour x 1/64 lb/lb-mol x 386.8 scf/lb-mol)/(8710 dscf/MMBtu x 1085 MMBtu/hour x (20.95/(20.95 – 15)) x 1 E06

SO_2 ppm = 0.6 ppm @ 15% O_2

The calculations demonstrate that the gas turbine meets Section 60.333(a). The calculations demonstrate that the gas turbine meets Section 60.333(a). After the February 24, 2006 revisions to 40 CFR Part 60 Subpart GG the facility is no longer required to monitor the sulfur content of the fuel to be in compliance with this NSPS (See 40 CFR 60.334(h)(3)).

40 CFR Part 72, Acid Rain Program

Source S-100 at Calpine Gilroy Cogen, L.P was previously exempt from the Acid Rain Program since it was a *qualifying facility*[1] that met the requirements listed in 40 CFR 72.6(b)(5) that states the following:
"(i) Has, as of November 15, 1990, one or more qualifying power purchase commitments to sell at least 15 percent of its total planned net output capacity."

S-100 no longer met the definition of a qualifying facility as of October 1, 2004. On February 2, 2005, Calpine submitted an Acid Rain application to the District for S-100.

Part 72, Subpart A, establishes general provisions and operating permit program requirements for sources and affected units under the Acid Rain program, pursuant to Title IV of the Clean Air Act. The facility continues to meet 72.9 Standard Requirements which requires the submission of a complete acid rain permit application, the possession of a valid acid rain permit, meeting the monitoring requirements of part 75, and holding sufficient allowances, and comply with the acid rain SO_2 limit. The facility must hold sufficient SO_2 allowances by March 1 (February 29 of a leap year) of every year to offset each ton of SO_2 emitted for the previous calendar year. The facility is expected to comply with the excess emissions, recordkeeping and reporting requirements in 72.9(e) and 72.9(f).

Part 72, Subpart C, contains requirements for acid rain permit applications and compliance plans. The facility is expected to continue to meet these requirements.

Part 72, Subpart E, contains the requirements for the acid rain permit which must include all elements of a complete acid rain application.

40 CFR Part 75, Continuous Emission Monitoring

Part 75, Subpart A, contains the applicability criteria, compliance dates, and prohibitions. The emissions units at the facility are subject to Part 72 and are therefore subject to Part 75. The NO_x monitoring is subject to part 75 per 75.2(c). The facility is expected to continue to meet the compliance dates and prohibitions contained in part 75 Subpart A.

Part 75, Subpart B, contains specific monitoring provisions for each pollutant subject to part 75. The emissions units at this facility are required to meet the SO_2, NO_x, CO_2 monitoring requirements contained in 75.10(a)(1), 75.10(a)(2), 75.10(a)(3) Opacity monitoring under 75.10(a)(4) is not required for gas fired units in accordance with 75.14(c). 75.10(b) requires

[1] A qualifying facility means a ''qualifying small power production facility'' within the meaning of section 3(17)(C) of the Federal Power Act or a ''qualifying cogeneration facility'' within the meaning of section 3(18)(B) of the Federal Power Act.

each CEM to meet equipment, installation, and performance specification in part 75 Appendix A and quality assurance/quality control in Appendix B. 75.10(c) requires heat input rate monitoring to meet requirements contained in part 75 Appendix F. The facility is expected to continue to comply with the requirements contained in 75.10(b) and (c).

75.10(d) contains primary equipment hourly operating requirements that require the CEM to monitor emissions when the emissions unit combusts fuel except as specified in 75.11(e) and during periods of calibration, quality assurance, or preventive maintenance, performed pursuant to §75.21 and appendix B of this part, periods of repair, periods of backups of data from the data acquisition and handling system, or recertification performed pursuant to §75.20. This section also contains requirements for calculating hourly averages from four 15-minute periods and validity of data and data substitution. Emission concentrations for a given hour are not considered valid unless it is based on four valid measurements. The data substitution requirements are contained in Subpart D. The facility is expected to continue to comply with the requirements contained in 75.10(d). 75.10(f) specifies minimum measurement capability requirement for CEMs and 75.10(g) contains the minimum recordkeeping and reporting requirements. The facility is expected to continue to meet 75.10(f) and (g).

75.11 contains specific provisions for SO_2 monitoring. 75.11(d)(2) allows the use of Appendix D to monitor SO_2 emissions from gas fired units. The facility monitors sulfur content of the natural gas to meet Part 75 SO_2 monitoring requirements.

75.12 contains specific provisions for NO_x emission rates. The facility uses a NO_x CEM and an O_2 monitor to meet this requirement.

75.13 contains CO_2 monitoring requirements. The facility monitors CO_2 in accordance with this section using the procedures in part 75 Appendix G.

75.14 contains opacity monitoring requirements. The facility is exempt from opacity monitoring under part 75 per 75.14(c).

Part 75 Subpart C contains operation and maintenance requirements including certification and recertification of the CEMs, quality assurance/quality control requirements, reference test methods, and out-of-control periods and adjustment for system bias. The facility is expected to continue to meet these requirements.

Part 75, Subpart D (75.30 through 75.36) contains Missing Data Substitution Procedures for SO_2, NO_x, flowrate, CO_2, and heat input procedures. The facility is expected to continue to meet these requirements.

Part 75, Subpart F contains the recordkeeping requirements including the contents of a part 75 monitoring plan. This subpart requires the facility to record the operating time, heat input rate, and load for each emissions unit. Additionally, the facility must record emissions data for SO_2, NO_x, CO_2, and O_2 along with quality assurance/quality control information.

Part 75, Subpart G contains the reporting requirements for affected facilities subject to part 75. The facility is expected to continue to meet these requirements.

S-101, S-102, Boilers

Table IV Source Specific Applicable Requirements was revised to change the effectiveness dates of applicable District Rules and Regulations and to add new applicable requirements to the boilers Table IV-C as shown below:

Action	Title/Description
Added BAAQMD Regulation 6-1-301	Ringlemann Number 1 Limitation to Table IV-C for the auxiliary boiler
Added BAAQMD Regulation 6-1-305	Visible Particles to Table IV-C for the auxiliary boiler
Added BAAQMD Regulation 6-1-310	Particulate Weight Limitation to Table IV-C for the auxiliary boiler
Added BAAQMD Regulation 6-1-310.3	Heat Transfer Operations to Table IV-C for the auxiliary boiler
Added BAAQMD Regulation 6-1-401	Appearance of Emissions
Added SIP Versions of Regulation 6	General Particulate Emissions
Added BAAQMD Regulation 9, Rule 3	Nitrogen Oxides from Heat Transfer Operations
Added BAAQMD Regulation 9, Rule 7	Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters
Added SIP Regulation 9, Rule 7 Requirements	Nitrogen Oxides and Carbon Monoxide from Industrial, Institutional, and Commercial Boilers, Steam Generators, and Process Heaters.
Updated regulatory citations for 40 CFR Part 60 Subpart A	General Requirements for New Source Performance Standards
Updated regulatory citations for 40 CFR Part 60 Subpart Db	Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

S-104, Cooling Tower

The following changes were made to Table IV-D for the cooling tower:

Action	Title/Description
Added BAAQMD Regulation 6 Rule 1 citations.	Particulate/Opacity Regulations
Added SIP Regulation 6 citations.	Particulate/Opacity Requirements

S-6, Fire Pump Diesel Engine

Table IV-E for the fire pump diesel engine has been deleted from the permit. Calpine has permanently shutdown S-6.

V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10.

The proposed Renewal Application does not change this section of the permit.

VI. Permit Conditions

Condition 2780 was revised to reflect the successful commissioning of the Dry Low NOx Combustors for S-100 on May 25th, 2011. Condition Parts 1a(i), 1b(i), 1c, 8 and 9a will be deleted from Condition 2780.

Condition 21961 was revised to reflect the successful commissioning of the Dry Low NOx Combustors for S-100 on May 25th, 2011. Condition Parts B (i), E 1(a) will be deleted from Condition 21961.

Condition 22851 regulating S-6 diesel fire pump was added to Table IV – E. This condition meets the Air Resources Board Air Toxics Control Measure for stationary diesel engines.

VII. Applicable Limits and Compliance Monitoring Requirements

This section of the permit is a summary of numerical limits and related monitoring requirements for each source. The summary includes a citation for each monitoring requirement, frequency of monitoring, and type of monitoring. The applicable requirements for monitoring are completely contained in Sections IV, Source-Specific Applicable Requirements, and VI, Permit Conditions, of the permit. Table VII B through D were combined with Table VII-A for the gas turbines and heat recovery steam generators since all of these sources are identical with similar applicable requirements and exhaust through a common stack.

Table VII-A Applicable Limits and Monitoring Requirements for the gas turbines (S-3, S-4, S-5) were revised as shown below:

Action	Title/Description
Added BAAQMD Regulation 9-9-301.1.3	Emission Limits Turbines Rated ≥ 10 MW with SCR
Added BAAQMD Regulation 9-9-301.2	NO_x Emission Limits General
Added SIP Version of Regulation 9, Rule 9	NO_x from Stationary Gas Turbines

Table VII-B Applicable Limits and Monitoring Requirements for the gas turbine (S-100) were revised as shown below:

Action	Title/Description
Added BAAQMD Regulation 9-9-301.1.2	Emission Limits Turbines Rated ≥ 10 MW with SCR
Deleted Reference to 9-9-301.1.3	NOx Limit for turbines with an SCR, S-100 does not have an SCR.
Added SIP Version of Regulation 9, Rule 9	NO_x from Stationary Gas Turbines
Added Regulation 6, Rule 1 requirements to Table	General Particulate Emissions
Updated SIP reference for Regulation 6 requirements	General Particulate Emissions
Update References to Condition 2780 to reflect the successful installation of the Dry Low NOx Combustors on S-100 on May 25th, 2011.	

Table VII-C Applicable Limits and Monitoring Requirements for the boilers were revised as shown below:

Action	Title/Description
Added Regulation 9, Rule 3 requirements	NO_x from Heat Transfer Operations
Added SIP Regulation 9-7-301.1	NO_x and CO from Boilers, Steam Generators, and Process Heaters
Added BAAQMD 9-7-307.6	NO_x and CO from Boilers, Steam Generators, and Process Heaters
Added BAAQMD 9-7-301.4	NO_x and CO from Boilers, Steam Generators, and Process Heaters
Added SIP 9-7-301.2	NO_x and CO from Boilers, Steam Generators, and Process Heaters
Added Regulation 6 Rule 1 requirements to Table	General Particulate Emissions
Updated SIP reference for Regulation 6 requirements	
Corrected NOx Limit for Condition 2780 part 4. Correct value is 40 ppm not 30 ppm.	

Table VII-D Applicable Limits and Monitoring Requirements for the cooling tower were added to the permit as shown below:

Action	Title/Description
Added Regulation 6 Rule 1 requirements to Table	General Particulate Emissions
Updated SIP reference for Regulation 6 requirements	

Table VII-E Applicable Limits and Monitoring Requirements for the fire pump diesel engine were revised as shown below:

Action	Title/Description
Added Regulation 6 Rule 1 requirements to Table	General Particulate Emissions
Updated SIP reference for Regulation 6 requirements	

Additional Monitoring Determinations

The tables below contain the limits for which there is no monitoring or potentially inadequate monitoring in the applicable requirements. The District has examined the monitoring for other limits and has determined that monitoring is adequate to provide a reasonable assurance of compliance. Calculations for potential to emit will be provided in the discussion when no monitoring is proposed due to the size of a source.

Monitoring decisions are typically the result of a balancing of several different factors including: 1) the likelihood of a violation given the characteristics of normal operation, 2) degree of variability in the operation and in the control device, if there is one, 3) the potential severity of impact of an undetected violation, 4) the technical feasibility and probative value of indicator monitoring, 5) the economic feasibility of indicator monitoring, and 6) whether there is some other factor, such as a different regulatory restriction applicable to the same operation, that also provides some assurance of compliance with the limit in question.

NOx Sources

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines	BAAQMD Regulation 9, Rule 9, Section 301.1.2	< 15 ppmv* @ 15% O_2, dry, 3-hr average *corrected for efficiency	CEMS
S-3, S-4, S-5 Turbines	BAAQMD Regulation 9, Rule 9, Section 301.2	< 5 ppmv @ 15% O2, dry, 3-hr average or ≤ 0.15 lbs/MWhr	CEMs
S-3, S-4, S-5 Turbines	SIP 9-9-301.3	9 ppmv @ 15% O2, dry	CEMS and Annual Source Test
S-3, S-4, S-5 Turbines	NSPS, 40 CFR 60.332 (a)(1)	99 ppmv @ 15% O_2, dry 4-hour rolling average (Arithmetic average of the average NO_x concentration measured by the CEMS for a given hour and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour)	CEMS
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 19.1	5 ppmv @ 15% O_2, dry, 1-hr average except during turbine startup or shutdown	CEMS
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	604.8 lb/calendar day (as NO_2) for S-3, S-4, and S-5 combined	CEMS and fuel monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	39.5 tons per calendar year (as NO_2) for S-3, S-4, and S-5 combined	CEMS and fuel monitoring
S100, Turbine	BAAQMD Regulation 9, Rule 9, Section 301.1.2	< 15 ppmv* @ 15% O_2, dry, 3-hr average *corrected for efficiency	CEMS

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S100, Turbine	BAAQMD Regulation 9, Rule 9, Section 301.2, effective after Dry Low NOx combustors becomes operational or no later than January 1, 2012	≤ 5 ppmv @ 15% O2, dry, 3-hr average or ≤ 0.15 lbs/MWhr	CEMS and fuel monitoring
S100, Turbine	SIP 9-9-305 and 9-9-401	≤ 21.0 ppmv* @ 15% O_2, dry, 3-hr average *corrected for efficiency	CEMS
S100, Turbine	NSPS, 40 CFR 60.332 (a)(1)	82 ppmv @ 15% O_2, dry 4-hour rolling average (Arithmetic average of the average NO_x concentration measured by the CEMS for a given hour and the three unit operating hour average NO_x concentrations immediately preceding that unit operating hour)	CEMS
S100, Turbine	BAAQMD Permit Condition 2780 part 1a(i)	Natural Gas or Fuel Oil < 25 ppmv @ 15% O2, 3-hr avg	CEMS
S100, Turbine	BAAQMD Permit Condition 2780 part 1a(ii), effective after Dry Low NOx combustors becomes operational or no later than January 1, 2012	Natural Gas or Fuel Oil < 5 ppmv @ 15% O2 or 0.15 lb/MW-hr, 3-hr avg	CEMS
S100, Turbine	BAAQMD Permit Condition 2780 part 1e	Natural Gas or Fuel Oil < 21 ppmv @ 15% O2, calendar day	CEMS
S100, Turbine	BAAQMD Permit Condition 2780 1f	323.7 tons/year of NOx	CEMS and fuel monitoring
S100, Turbine	BAAQMD Permit Condition 2780 1g	1876 lb/day of NOx	CEMS and fuel monitoring
S100, Turbine	BAAQMD Permit Condition 21961, PSD permit, part IX-C.	Natural Gas or Fuel Oil < 25 ppmv @ 15% O2, dry	CEMS
S101, S102, Boilers	BAAQMD 9-7-301.1	30 ppmv @3%O_2, dry, 3-hr average	CEMS
S101, S102, Boilers	SIP 9-7-301.1	30 ppmv @3%O_2, dry, 3-hr average	CEMS
S101, S102, Boilers	BAAQMD 9-7-307.6, 1/1/14 1st Unit, 1/1/15 2nd Unit	5 ppmv @3%O_2, dry, 3-hr average	CEMS
S101, S102, Boilers	NSPS 60.44b(a)	0.2 lb/MM Btu, averaged over 24 hrs	None
S101, S102, Boilers	BAAQMD Permit Condition 2780 part 4	40 ppmv @3%O2, dry, averaged over 3 hours	CEMS
S101, S102, Boilers	BAAQMD Permit Condition 21961, PSD permit, part IX-C.	40 ppmv @3%O2, dry, averaged over 3 hours	CEMS

NOx Discussion:

The turbines are subject to the NO_x emission limitations in District Regulation 9, Rule 9 (Monitoring and Recordkeeping Requirements). This facility has several stationary gas turbines (S-3, S-4, S-5 and S-100) with a heat input rate greater than 150 MMBtu/hr and operates more than 4000 hours in a 36-month period. Therefore each turbine is required to have Continuous Emission Monitoring (CEM) and to complete an annual source test (BAAQMD Regulation 9-9-501). S-100 is also required to have a NOx CEM in accordance with Regulation 1-520.

The CEMs are used to demonstrate compliance with the NO_x concentration permit limits on a continuous basis. An annual relative accuracy test audit (RATA) is required for each NO_x CEM to ensure accuracy (40 CFR Part 75, BAAQMD MOP Volume V). NO_x mass emissions are calculated using NO_x and O_2 CEM data, and the fuel heat input rate (from fuel flow meter). The District has determined that no additional monitoring is required.

The boilers also use CEMs to demonstrate compliance with NO_x permit limits except for the NSPS NOx limit in 40 CFR, Part 60.44b(a). Continuous compliance does not need to be demonstrated with this limit since the other NO_x limits regulating boiler emissions are much more stringent. A limit of 0.2 lb/MMBtu corresponds to 164.8 ppmvd @ 3% O_2. Currently, boilers are required to meet a 30 ppmvd @3% O_2 NOx limit and in the future will be required to meet a 5 ppmvd @3% O_2 NOx limit. No ongoing monitoring is necessary to demonstrate compliance with the NSPS NO_x limit for the boilers. The CEMs are used to demonstrate compliance with the NO_x concentration permit limits on a continuous basis. The District has determined that no additional monitoring is required.

CO Sources

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 19.3	6 ppmv @ 15% O_2, dry, 3-hr average except during turbine startup or shutdown	CEMS, Source test every 8,000 hours or every three years whichever comes first
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	446.1 lb/calendar day for S-3, S-4, and S-5 combined	CEMS and fuel monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	36.0 tons per calendar year for S-3, S-4, and S-5 combined	CEMS and fuel monitoring
S100, Turbine, S-101, S102, Boilers	BAAQMD Permit Condition 2780 part 3b	Emissions < 100 tons/yr (S-100, S-101, and S-102)	CEMS and fuel monitoring
S100, Turbine	BAAQMD Permit Condition 2780 part 3c	10 ppmvd @ 15% O_2, 3-hr average, except during startup, shutdown, operation at < 80% load, and operation at low ambient temperature	CEMS
S100, Turbine	BAAQMD Permit Condition 2780 part 3d	< 14670 lbs. CO during startups and shutdowns per any consecutive 12-month period	CEMS and fuel monitoring

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S100, Turbine	BAAQMD Permit Condition 2780 part 3e	< 14.8 tons CO during operation at < 80% load per any consecutive 12-month period, < 750 hours of operation at < 80% load per any consecutive 12-month period	CEMS and fuel monitoring
S100, Turbine	BAAQMD Permit Condition 2780 part 3f	15 ppmvd @ 15% O_2, 1-hr average, during operation at low ambient temperature, < 100 hours of operation at ambient temperatures < 35^o F. per any consecutive 12-month period	CEMS
S101, S102, Boilers	BAAQMD 9-7-301.4	400 ppmv @ 3% O_2, dry, 3-hr average	
S101, S102, Boilers	SIP 9-7-301.2	400 ppmv @ 3% O_2, dry, 3-hr average	

CO Discussion:

S-3, S-4, and S-5 have CO CEMS installed since these sources have a large potential to emit for CO. S-100, S-101 and 102 have CO CEMS installed in accordance with Condition 2780 part 11.

The CEMs are used to demonstrate compliance with the CO concentration permit limits on a continuous basis. An annual relative accuracy test audit (RATA) is required for each CO CEM to ensure accuracy (40 CFR Part 75, BAAQMD MOP Volume V). CO mass emissions are calculated using CO and O_2 CEM data, and the fuel heat input rate (from fuel flow meter). The District has determined that no additional monitoring is required.

The CO emission rate for boilers such as S-101 and S-102, that exclusively combust natural gas was taken from US EPA's AP-42, Table 1.4-1 "Emission Factors for Nitrogen Oxides (NOx) and Carbon Monoxide (CO) from Natural Gas Combustion", July 1998. Specifically, the CO emission factor for Large Wall-Fired Boilers (Heat Input > 100 MMBTU/hr) in the above table is 84 lb/10^6 scf.

The CO limit prescribed in Regulation 9-7-301.4 and SIP 9-7-301.2 is 400 ppmv @ 3% O2. In order to compare the standard emission rate prescribed in AP-42 to the afore-referenced Regulation 9, Rule 7 limit, we need to convert both emission rates to an emission rate with the same metric (lb/MM BTU).

We can convert the Regulation 9, Rule 7 limit to lb/MM BTU as follows:
= (400 ppmvd) (20.95 – 0)/(20.95 – 3) = 466.85 ppmv CO @ 0% O2
= (466.85/10E6) (1 lbmol/385.3 dscf) (28 lb CO/lbmol) (8535 dscf/MMBTU)
= 0.29 lb CO/MMBTU

If we are to divide the standard AP-42 emission factor by heating value of natural gas (1,020 BTU/scf), we derive an emission rate of 0.08 lb/MM BTU.

Since, the AP-42 emission rate is below the Regulation 9-7-301.2 limit, it is concluded that periodic CO monitoring for S-101 and S-102 is not necessary to demonstrate compliance with the above limit.

SO_2 Sources

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines, S-100, Turbine, S-101, S-102 Boilers	BAAQMD Regulation 9-1-301	GLC[1] of 0.5 ppm for 3 min or 0.25 ppm for 60 min or 0.05 ppm for 24 hours	None
S-3, S-4, S-5 Turbines, S-100, Turbine, S-101, S-102 Boilers	BAAQMD Regulation 9-1-302	300 ppm (dry)	None
S-3, S-4, S-5 Turbines, S-100, Turbine	NSPS GG 40 CFR 60.333(a) or 60.333(b)	SO_2 in gases exiting turbine ≤ 0.015% (vol.) @15% O_2 (dry) or Total sulfur in fuel combusted in turbines ≤ 0.8% by wt. (8000 ppmw)	None
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 19.6	0.33 lb/clock hr for S-3, S-4, and S-5 combined	Total sulfur and hydrogen sulfide analysis and fuel monitoring, Source test every 8,000 hrs or every 3 yrs, whichever comes first
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	23.8 lb/calendar day for S-3, S-4, and S-5 combined	Total sulfur and hydrogen sulfide analysis and fuel monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	1.9 tons/calendar year for S-3, S-4, and S-5 combined	Total sulfur and hydrogen sulfide analysis and fuel monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 23.b	Total sulfur content in natural gas combusted in turbines ≤ 1.0 gr/100 scf	Total sulfur analysis

SO_2 Discussion:

BAAQMD Regulation 9-1-301 and 302

Area monitoring to demonstrate compliance with the ground level SO_2 concentration requirements of Regulation 9-1-301 is at the discretion of the APCO (per BAAQMD Regulation 9-1-501). This facility does not have equipment that emits large amounts of SO_2 and therefore is not required to have ground level monitoring by the APCO.

All facility combustion sources are subject to the SO_2 emission limitations in District Regulation 9, Rule 1 (ground-level concentration and emission point concentration). In EPA's June 24, 1999 agreement with CAPCOA and ARB, "Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", EPA has agreed that natural-gas-fired combustion sources do not need additional monitoring to verify compliance with Regulation 9, Rule 1, since violations of the regulation are unlikely. Therefore, no monitoring is necessary for this requirement.

Compliance with 40 CFR 60.333(a) in NSPS GG:

Section 60.333(a) requires an owner/operator of stationary turbines to demonstrate compliance with either one of the following two conditions:

- Discharge SO_2 at less than or equal to 0.015% by volume at 15% oxygen on a dry basis or
- Combust fuel with sulfur content less than or equal to 0.8% by weight (8000 ppmw).

The typical annual average sulfur concentration of the PUC quality natural gas combusted in the turbines is 0.25 grains/100 scf. PG&E natural gas has a maximum sulfur concentration of 1 grain/100 scf (See PG&E Gas Rule 21, Section C). The SO_2 content in the natural gas can be compared to Section 60.333(a) as follows:

lb S/MMBtu = 1 grains/100 scf x lb/7000 grains x scf/1020 Btu x 1 E06 Btu/MMBtu

lb S/MMBtu = 1.4 E-03

lb SO_2/MMBtu = 1.4 E-03 lb/MMBtu x (64 lb SO_2/lb-mol/32 lb S/lb-mol)

lb SO_2/MMBtu = 2.8 E-03

S-3, S-4, S-5

SO_2 lb/hour = 2.8 E-03 lb/MMBtu x 467.6 MMBtu/hour = 1.31

SO_2 ppm = (1.31 lb/hour x 1/64 lb/lb-mol x 386.8 scf/lb-mol)/(8710 dscf/MMBtu x 467.6 MMBtu/hour x (20.95/(20.95 – 15)) x 1 E06

SO_2 ppm = 0.6 ppm @ 15% O_2

<u>S-100</u>

SO_2 lb/hour = 2.8 E-03 lb/MMBtu x 1085 MMBtu/hour = 3.04

SO_2 ppm = (3.04 lb/hour x 1/64 lb/lb-mol x 386.8 scf/lb-mol)/(8710 dscf/MMBtu x 1085 MMBtu/hour x (20.95/(20.95 – 15)) x 1 E06

SO_2 ppm = 0.6 ppm @ 15% O_2

The calculations demonstrate that the gas turbines at the facility meet Section 60.333(a). After the February 24, 2006 revisions to 40 CFR Part 60 Subpart GG the facility is no longer required to monitor the sulfur content of the fuel to be in compliance with this NSPS (See 40 CFR 60.334(h)(3)). The facility is required under 40 CFR Part 75 monitoring requirements to track fuel usage and sulfur content to estimate SO_2 emissions from each gas turbine. The facility also tracks fuel usage and sulfur content to estimate SO_2 emissions from the auxiliary boilers. The District has reviewed the SO2 monitoring requirements for the facility and determined that no additional monitoring is required.

PM Sources

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines, S-100, Turbine, S-101, S-102 Boilers S-104 Cooling Tower	BAAQMD Regulation 6-1-301	> Ringelmann No. 1 for no more than 3 minutes in any hour	None
S-3, S-4, S-5 Turbines, S-100, Turbine, S-101, S-102 Boilers S-104 Cooling Tower	SIP 6--301	> Ringelmann No. 1 for no more than 3 minutes in any hour	None
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 18	> Ringelmann No. 1 for no more than 3 minutes in any hour or equivalent 20% opacity	None
S-3, S-4, S-5 Turbines S-104 Cooling Tower	BAAQMD Regulation 6-1-310	0.15 gr/dscf	None
S-3, S-4, S-5 Turbines S-104 Cooling Tower	SIP 6-310	0.15 gr/dscf	None
S-100, Turbine, S-101, S-102 Boilers	BAAQMD Regulation 6-1-310.3	0.15 grain/dscf @6% O_2	None
S-100, Turbine, S-101, S-102 Boilers	SIP 6-310.3	0.15 grain/dscf @6% O_2	None
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 19.5	2.5 lb/clock hr for each turbine, except during turbine startup or shutdown	Source test every 8,000 hrs or every 3 yrs, whichever comes first
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	180 lb/calendar day for S-3, S-4 & S-5 combined	Source test every 8,000 hrs or every 3 yrs, whichever comes first, and fuel monitoring

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	14.7 tons/year for S-3, S-4 & S-5 combined	Source test every 8,000 hrs or every 3 yrs, whichever comes first, and fuel monitoring
S-100, Turbine, S-101, S-102 Boilers	BAAQMD Permit Condition 2780, part 6	< 25 TPY total FP for S-100, S-101, S-102	None
S-104 Cooling Tower	BAAQMD Regulation 6-1-301	Ringelmann No. 1	None
S-104 Cooling Tower	BAAQMD Regulation 6-1-310	0.15 gr/dscf	None
S-104 Cooling Tower	BAAQMD Regulation 6-1-311	$4.10P^{0.67}$ lb/hr, where P is process weight, ton/hr	None
S-104 Cooling Tower	SIP 6-311	$4.10P^{0.67}$ lb/hr, where P is process weight, ton/hr	None

PM Discussion:

BAAQMD Regulation 6, Rule 1 “Particulate Matter and Visible Emissions”

Visible Emissions, 6-1-301

BAAQMD Regulation 6, Rule 1 requirements limit visible emissions from these sources. Visible emissions are normally not associated with combustion of gaseous fuels, such as natural gas. Sources S-3, S-4, S-5, S-100 Gas Turbines burn natural gas exclusively; therefore, per the EPA's June 24, 1999 agreement with CAPCOA and ARB titled "Summary of Periodic Monitoring Recommendations for Generally Applicable Requirements in SIP", no monitoring is required to ensure compliance with these limits for these sources.

S-104 Cooling Tower is not expected to emit visible particulate emissions. Therefore, no monitoring is required to ensure compliance with Regulation 6-1-301 for this source.

Particulate Weight Limitation

BAAQMD Regulation 6-1-310 (6-310 SIP) limits filterable particulate (FP) emissions from any source to 0.15 grains per dry standard cubic foot (gr/dscf) of exhaust volume. This is a “grain loading” standard.

Exceedances of the grain loading standards are normally not associated with combustion of gaseous fuels, such as natural gas. Sources S-3, S-4, S-5, S-100 burn natural gas exclusively, therefore, per the EPA's July 2001 agreement with CAPCOA and ARB entitled "CAPCOA/CARB/EPA Region IX Recommended Periodic Monitoring for Generally Applicable Grain Loading Standards in the SIP: Combustion Sources: Summary of Periodic Monitoring

Recommendations for Generally Applicable Requirements in SIP", no monitoring is required to ensure compliance with this limit for these sources.

The grain loading from the S-104 Cooling Tower is expected to be much less than 0.15 grains per dscf. Therefore, no monitoring is required to ensure compliance with this limit for this source.

The worst-case grain loading from S-104 is calculated, per information provided in the cooling tower vendor data sheet and the reclaimed water properties, as follows:

Cooling water circulation rate	24,000 gpm
Drift rate	0.002%
Maximum total dissolved solids	6,000 ppm
Minimum Exhaust gas flow rate:	540,500 dscfm

Cooling tower drift:

(24,000 gal/min)(60 min/hr)(8.34 lb/gal)(0.00002) = 240 lb/hr

Max. PM_{10} emission rate = (240 lb/hr)(6,000 ppm)/10^6
= 1.44 lb/hr

Grain loading = (1.44 lb/hr)(hr/60 min)(7000 gr/lb)/(540,500 dscfm)
= 0.00031 gr/dscf

BAAQMD Permit Condition 18102

S-3, S-4 and S-5 are source tested every 8,000 hours of operation or every three years whichever comes first. The facility uses the source test results to develop emission factors per unit fuel combusted and tracks fuel usage to calculate particulate emissions from these gas turbines. The District has reviewed this monitoring and determined no additional particulate monitoring is necessary.

BAAQMD Permit Condition 2780

S-100, S-101, and S-102, were issued an Authority to Construct under Application 30331 in April 1985. Emission calculations performed under the above application assumed S-100 would combust fuel oil and natural gas for 3250 hours/yr and 5335 hours/yr, respectively and the boilers S-101 & S-102 would operate for 1975 hours/yr when either of the above fuels. It was further assumed that the sources would operate for 14 hours per day. The daily Total Suspended Particulate (TSP) emission rates for the turbine and boilers when combusting fuel oil was estimated to be equal to 180 lbs/day and 32 lbs/day, respectively. In similar fashion, the daily TSP emission rates for the turbine and boilers when combusting natural gas was estimated to be equal to 60 lbs/day and 13 lbs/day, respectively. The above assumptions yielded a total annual TSP emission rate (from S-100 through S-102) of 23 TPY and 12 TPY , when combusting fuel oil and natural gas, respectively. To ensure the combined TSP emissions from the turbine and boilers would not exceed the prevailing de minimis TSP PSD emission level of 25 TPY, part 5 of the above condition explicitly limited TSP emissions from the above sources to not exceed 25 TPY.

The facility exclusively combusts PUC quality natural gas and fuel oil is no longer combusted in any of the above sources. In light of the above, it is safe to conclude that the above sources can easily comply with the annual TSP limit of 25 TPY. Therefore, no further monitoring is necessary at the above sources to demonstrate compliance with part 6 of permit condition 2780.

POC Sources

S# & Description	Emission Limit Citation	Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 19.4	2 ppmv @ 15% O2, dry, 3-hr average except during turbine startup or shutdown	Source test every 8,000 hrs or every 3 yrs, which ever comes first
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	84 lb/calendar day for S-3, S-4, and S-5 combined	Source test every 8,000 hrs or every 3 yrs, whichever comes first, and fuel monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, part 22	6.9 ton/calendar year for S-3, S-4, and S-5 combined	Source test every 8,000 hrs or every 3 yrs, whichever comes first, and fuel monitoring
S-100, Turbine, S-101, S-102 Boilers	BAAQMD Permit Condition 2780, part 6	< 40 TPY NMHC for S-100, S-101, S-102	None

POC Discussion:

S-3, S-4 and S-5 are source tested every 8,000 hours of operation or every three years whichever comes first. The facility uses the source test results to develop emission factors per unit fuel combusted and tracks fuel usage to calculate particulate emissions from these gas turbines. The District has reviewed this monitoring and determined no additional POC monitoring is necessary.

S-100 through S-102 at Calpine Gilroy Cogen, L.P. were permitted under Application 30331 in April 1985. Emission calculations performed under the afore-referenced application assumed the above sources would combust both fuel oil and natural gas. Specifically, it was assumed that the turbine and boilers would combust fuel oil for 1,975 hrs/yr and 3,250 hrs/yr, respectively. The annual NMHC emissions from the turbine and boilers were estimated to be equal to 39 TPY. To ensure the combined emissions from the turbine and boilers would not exceed the prevailing de minimis PSD emission level of 40 TPY, the above condition explicitly limited POC emissions from the above sources to not exceed 40 TPY.

Following is a POC potential to emit (PTE) demonstration for sources S-100 through S-102 using US EPA AP-42 emission factors.

S-100:
Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases from Stationary Gas Turbines" provides an uncontrolled VOC emission factor of 0.0021 lbs/MMBTU. The maximum heat input for S-100 is 1,085 MMBTU/hr.

Assuming S-100 operates for 8,760 hrs/yr, the maximum uncontrolled POC emissions from S-100 is equal to:
= 0.0021 lbs/MMBTU x 1085 MMBTU/hr x 8760 hrs/yr x 1 ton/2000 lbs = 9.98 TPY

S-101 & S-102:
Table 1.4-2 "Emission Factors for Criteria Pollutants and Greenhouse Gases from Natural Gas Combustion" provides an uncontrolled VOC emission factor of 5.5 lbs/MMscf (0.0054 lbs/MMBTU) .

Assuming each boiler operates for 8,760 hrs/yr, the maximum uncontrolled POC emissions from either boiler is equal to:
= 0.0054 lbs/MMBTU x 104 MMBTU/hr/boiler x 8760 hrs/yr x 1 ton/2000 lbs
= 2.46 TPY/boiler ~ 4.92 TPY for both boilers.

Therefore, the POC PTE for sources S-100 through S-102 is 14.9 TPY.

Based on the PTE demonstration discussed above and given the fact that all the sources will exclusively combust natural gas, it is safe to conclude that monitoring to ensure the POC limit (< 40 TPY) is not exceeded is not necessary.

NH_3 Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
S-3, S-4, S-5 Turbines	BAAQMD condition #18102, Part 19.2	10 ppmv @ 15% O_2, dry, averaged over 3 hrs except during turbine startup or shutdown	Ammonia injection rate monitor, calculations, and periodic source testing every 8,000 hrs or every 3 yrs, which ever comes first

NH_3 Discussion:

Maximum Concentration Limits
Ammonia (NH_3) emissions from S-3, S-4, and S-5 shall not exceed 10 ppmvd @ 15% O2, except during periods of startup and shutdown as defined in this permit. The NH_3 monitoring is based on the source test and NH_3 to NOx ratio at the inlet to SCR. The slip calculation and correction factor is determined by periodic source testing.

The periodic source testing and ongoing monitoring of the ammonia injection rate is adequate to ensure compliance with the ammonia permit limits. There is no EPA approved ammonia continuous emission monitor available with appropriate quality assurance/quality control protocols.

VIII. Test Methods

This section of the permit lists test methods that are associated with standards in District or other rules. It is included only for reference. In most cases, the test methods in the rules are source test methods that can be used to determine compliance but are not required on an ongoing basis. They are not applicable requirements.

If a rule or permit condition requires ongoing testing, the requirement will also appear in Section IV of the permit.

The proposed Renewal Application will make minor editorial changes shown in Table VIII Test Methods of the draft permit.

IX. Acid Rain

The Acid Rain permit is incorporated into the Title V permit in this section. The effective dates of the permit will be revised upon permit issuance. The allowance tables for S-3, S-4, and S-5 were updated. An allowance table was added for S-100. The contact phone numbers were updated in the Acid Rain Permit.

X. Permit Shield

The existing permit shield identifying specific applicable requirements that do not apply to the facility shown in Table X-A have not been removed from the Title V permit. The permit shields granted for monitoring, reporting and recordkeeping requirements contained in Table X-B-1 for the boiler have been removed from the Title V permit.

XI. Revision History

This section details the revision history of the facility's Title V permit.

Changes to permit:

The renewal permit contains the following updated information regarding the application for renewal:

TBD, 2011 Title V Renewal Application No. 22569

XII. Glossary

No changes were made to this section.

XIII Title IV Permit Application

The Acid Rain permit application for the facility is part of the Title V permit and is included here.

D. Alternate Operating Scenarios

No alternate operating scenario has been requested for this facility.

E. Compliance Status

A inter-office memorandum dated November 22, 2011 from the Director of Compliance and Enforcement, to the Director of Engineering, presents a review of the compliance record of Calpine Gilroy Cogen, LP & Calpine Gilroy Energy Center (Site #: B1180). The Compliance and Enforcement Division staff has reviewed the records for Calpine Gilroy Cogen, LP & Calpine Gilroy Energy Center (Site #: B1180) for the period between September 22, 2006 through November 22, 2011. This review was initiated as part of the District evaluation of an application by Calpine Gilroy Cogen, LP & Calpine Gilroy Energy Center (Site #: B1180) for a Title V permit. During the period subject to review, activities known to the District include:

- There was one Notices of Violation issued during this review period on 5/23/2007. One of the peaking units exceeded its ammonia permit limit during a compliance test. This was a single day occurrence and the issue has been resolved.
- The District did not receive any alleged complaints.
- The facility is not operating under a Variance or an Order of Abatement from the District Board.
- The facility operated under two separate compliance and enforcement agreements during 2011 that allowed the facility to exceed permit limits while commissioning the new Dry Low NOx combustors. The installation of the new combustors will reduce NOx emissions significantly (Limit of 21 ppm NO_x @ 15% O_2 will be reduced to 5 ppm NO_x @ 15% O_2). Commissioning of the new Dry Low NO_x combustors is expected to be completed by January 1, 2012.
- There were no monitor excesses or equipment breakdowns reported or documented by District staff.

The owner certified that all equipment was operating in compliance on an annual basis during the period. No ongoing non-compliance issues have been identified to date.

APPENDIX A

Glossary

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

Basis
The rule or regulation that gives the District authority to impose requirements

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEQA
California Environmental Quality Act

CFR
The Code of Federal Regulations - 40 CFR contains the implementing regulations for federal environmental statutes such as the Clean Air Act. Parts 50-99 of 40 CFR contain the requirements for air pollution programs.

CO
Carbon Monoxide

Cumulative Increase
The sum of permitted emissions from each new or modified source since a specified date pursuant to BAAQMD Rule 2-1-403, Permit Conditions (as amended by the District Board on 7/17/91) and SIP Rule 2-1-403, Permit Conditions (as approved by EPA on 6/23/95). Cumulative increase is used to determine whether threshold-based requirements are triggered.

District
The Bay Area Air Quality Management District

dscf
Dry Standard Cubic Feet

EPA
The federal Environmental Protection Agency.

Excluded
Not subject to any District regulations.

Federally Enforceable, FE
All limitations and conditions which are enforceable by the Administrator of the EPA including those requirements developed pursuant to 40 CFR Part 51, subpart I (NSR), Part 52.21 (PSD), Part 60 (NSPS), Part 61 (NESHAPs), Part 63 (MACT), and Part 72 (Permits Regulation, Acid Rain), including limitations and conditions contained in operating permits issued under an EPA-approved program that has been incorporated into the SIP.

FP
Filterable Particulate as measured by BAAQMD Method ST-15, Particulate.

HAP
Hazardous Air Pollutant. Any pollutant listed pursuant to Section 112(b) of the Act. Also refers to the program mandated by Title I, Section 112, of the Act and implemented by 40 CFR Part 63.

Major Facility
A facility with potential emissions of: (1) at least 100 tons per year of regulated air pollutants, (2) at least 10 tons per year of any single hazardous air pollutant, and/or (3) at least 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity of hazardous air pollutants as determined by the EPA administrator.

MFR
Major Facility Review. The District's term for the federal operating permit program mandated by Title V of the Federal Clean Air Act and implemented by District Regulation 2, Rule 6.

MOP
The District's Manual of Procedures.

NAAQS
National Ambient Air Quality Standards

NESHAPS
National Emission Standards for Hazardous Air Pollutants. See in 40 CFR Parts 61 and 63.

NMHC
Non-methane Hydrocarbons (Same as NMOC)

NMOC
Non-methane Organic Compounds (Same as NMHC)

NO_x
Oxides of nitrogen.

NSPS
Standards of Performance for New Stationary Sources. Federal standards for emissions from new stationary sources. Mandated by Title I, Section 111 of the Federal Clean Air Act, and implemented by 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for pre-construction review and permitting of new and modified sources of pollutants for which criteria have been established in accordance with Section 108 of the Federal Clean Air Act. Mandated by Title I of the Federal Clean Air Act and implemented by 40 CFR Parts 51 and 52 and District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets for the emissions from a new or modified source. Applies to emissions of POC, NO_x, PM_{10}, and SO_2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and is not exempted by 40 CFR 72 from Titles IV and V of the Clean Air Act.

POC
Precursor Organic Compounds

PM
Particulate Matter

PM_{10}
Particulate matter with aerodynamic equivalent diameter of less than or equal to 10 microns

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of those air pollutants for which the District is classified "attainment" of the National Air Ambient Quality Standards. Mandated by Title I of the Act and implemented by both 40 CFR Part 52 and District Regulation 2, Rule 2.

SIP
State Implementation Plan. State and District programs and regulations approved by EPA and developed in order to attain the National Air Ambient Quality Standards. Mandated by Title I of the Act.

SO_2
Sulfur dioxide

THC
Total Hydrocarbons (NMHC + Methane)

Title V
Title V of the federal Clean Air Act. Requires a federally enforceable operating permit program for major and certain other facilities.

TOC
Total Organic Compounds (NMOC + Methane, Same as THC)

TPH
Total Petroleum Hydrocarbons

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

VOC
Volatile Organic Compounds

Units of Measure:

bhp	=	brake-horsepower
btu	=	British Thermal Unit
cfm	=	cubic feet per minute
g	=	grams
gal	=	gallon
gpm	=	gallons per minute
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m^2	=	square meter
min	=	minute
mm	=	million
MMbtu	=	million btu
MMcf	=	million cubic feet
ppmv	=	parts per million, by volume
ppmw	=	parts per million, by weight
psia	=	pounds per square inch, absolute
psig	=	pounds per square inch, gauge
scfm	=	standard cubic feet per minute
yr	=	year

APPENDIX B

BAAQMD Compliance Report

COMPLIANCE & ENFORCEMENT DIVISION

Inter-Office Memorandum

November 22, 2011

TO: JOHN CHILADAKIS – DIRECTOR OF ENGINEERING

FROM: BRIAN BATEMAN – DIRECTOR OF ENFORCEMENT

SUBJECT: REVIEW OF COMPLIANCE RECORD OF:

CALPINE GILROY COGEN, LP & CALPINE GILROY ENERGY CTR, LLC; B1180

Background

This review was initiated as part of the District evaluation of an application by Calpine Gilroy Cogen, LP & Calpine Gilroy Energy CTR, LLC (Calpine Gilroy), for a Title V Permit Renewal. It is standard practice of the Compliance and Enforcement Division to undertake a compliance record review in advance of a renewal of a Title V Permit. The purpose of this review is to assure that any non-compliance problems identified during the prior five-year permit term have been adequately addressed, or, if non-compliance persists, that a schedule of compliance is properly incorporated into the Title V permit compliance schedule. In addition, the review checks for patterns of recurring violation that may be addressed by additional permit terms. Finally, the review is intended to recommend, if necessary, any additional permit conditions and limitations to improve compliance.

Compliance Review

Compliance records were reviewed for the time period from September 22, 2006 through November 22, 2011. The results of this review are summarized as follows:

1. Violation History

Staff reviewed Calpine Gilroy, Annual Compliance Certifications, and found no ongoing non-compliance and no recurring pattern of violations.

Staff also reviewed the District compliance records. During this period Calpine Gilroy, activities known to the District include:

District-issued Notices of Violation:

NOV#	Regulation	Date Occur	# of Days	Comments	Disposition
A48021	2-6-307	5/23/2007	1	Failure to meet Title V permit condition	Resolved

Violation was for an ammonia emissions exceedence, recorded during source testing (outside contractor) source test#OS-1944. District permit condition #18102, Section 19.2 Ammonia emissions from the gas turbine shall not exceed 10 ppmvd @ 15% O2 (3-hour rolling average), except during periods of startup and shutdown as defined in this permit.

2. Complaint History

The District received no air pollution complaints during this review period.

3. Reportable Compliance Activity

Reportable Compliance Activity (RCA), also known as "Episode" reporting, is the reporting of compliance activities involving a facility as outlined in District Regulations and State Law. Reporting covers breakdown requests, indicated monitor excesses and inoperative monitor reports.

Within the review period, the District received 12 notifications for RCA's. There were no air quality violations issued as a result of these RCA's.

The District received the following notifications for Reportable Compliance Activities (RCA):

Episode	Date Occur	# of Days	Comments	Disposition
05X07	10/8/2006	1	Mechanical breakdown of flue gas recirculation (FGR) on S-102, boiler	Breakdown Relief Granted
05X08	10/8/2006	1	Continuous Emission Monitor (CEM) indicated excess of Nitrogen Oxides (NOx) associated with 05X07	Breakdown Relief Granted
04Y62	1/16/2007	1	Malfunction of Ammonia (NH3) control valve on S-3, natural gas Combustion Turbine (CT), due to blown fuse in sample line heater of CEM	Breakdown Relief Granted
04Y63	1/16/2007	1	CEM indicated excess of NOx associated with 04Y62	Breakdown Relief Granted
05B43	8/2/2007	1	CEM indicated excess of Carbon monoxide (CO) for S-100, natural gas CT	No Action taken, not an excess
05C97	12/4-6/2007	2	Inoperative monitor, NOx analyzer failure	Inoperative monitor-corrected: no further action

REVIEW OF COMPLIANCE RECORD OF:
CALPINE GILROY COGEN, LP & CALPINE GILROY ENERGY CTR, LLC – B1180
October 27, 2011
Page 3 of 3

05C99	12/4-6/2007	2	CEM indicated excess of NOx for S-4, natural gas CT, associated with 05C97	No Action Taken, not an excess
05D76	1/18/2008	1	Parametric excess, NH3, associated with S-4, natural gas CT	No Action Taken, not an excess
05D79	1/23/2008	1	Parametric excess, NH3, associated with S-4, natural gas CT	No Action Taken, not an excess
05K02	11/24/2008	1	Mechanical breakdown of FGR on S-101, boiler	No Action Taken, not an excess
05K03	11/24/2008	1	CEM indicated excess of CO associated with 05K03	No Action Taken, not an excess
05M23	5/7/2009	1	CEM excesses, NOx and CO, associated with S-100, S-101, and S-102	No Action Taken, no excesses occurred

4. Enforcement Agreements, Variances, or Abatement Orders

There were no abatement orders for Calpine Gilroy, over this review period.

Calpine Gilroy applied for an emergency variance in September of 2009, for S-5, natural gas CT, from permit condition limits on NOx and CO, docket # 3570. This variance was granted to the facility by the District Hearing Board.

Calpine Gilroy entered into an enforcement agreement with the District on May 16, 2011, regarding possible emissions excesses of NOx and CO associated with the commissioning and tuning of S-100, natural gas CT.

Calpine Gilroy extended their enforcement agreement with the District on November 7, 2011, to allow additional combustor tuning up to 24 hours of operation with a CO limit of 50 ppm instead of 10 ppm. The enforcement agreement ends on January 1, 2012.

Conclusion

Following its review of all available facility and District compliance records for Calpine Gilroy, the District's Compliance and Enforcement Division has determined that Calpine Gilroy was in intermittent compliance from the date of the last permit renewal, on September 22, 2006, through the present. However, Calpine Gilroy has demonstrated no evidence of ongoing noncompliance and no recurring pattern of violations that would warrant consideration of a Title V permit compliance schedule for this facility.

Based on this review, the District has concluded that no schedule of compliance or change in permit terms is necessary beyond what is already contained in the facility's current Title V permit.

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APPENDIX C

Toxic Air Contaminants Potential to Emit Calculations

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

Toxic Air Contaminant	**Facility (lb/hour)**	**Facility (lb/year)**	**Acute Risk Screening Trigger Level (lb/hr)**	**Chronic Risk Screening Trigger Level (lb/yr)**	**Facility (ton/year)**	**Description**
1,3-Butadiene	3.22E-04	1.87E+00	None	6.30E-01	9.34E-04	
Acetaldehyde	3.47E-01	2.01E+03	None	3.80E+00	1.01E+00	
Acrolein	4.79E-02	2.78E+02	5.50E-03	1.40E+01	1.39E-01	
Ammonia	2.10E+01	7.69E+04	7.10E+00	7.70E+03	3.85E+01	not a HAP
Benzene	3.41E-02	1.96E+02	2.90E+00	3.80E+00	9.82E-02	
Benzo(a)anthracene	5.73E-05	3.32E-01	None	None	1.66E-04	*included in Specified PAHs*
Benzo(a)pyrene	3.52E-05	2.04E-01	None	6.90E-03	1.02E-04	*included in Specified PAHs*
Benzo(b)fluoranthene	2.86E-05	1.66E-01	None	None	8.31E-05	*included in Specified PAHs*
Benzo(k)fluoranthene	2.79E-05	1.62E-01	None	None	8.09E-05	*included in Specified PAHs*
Chrysene	6.39E-05	3.71E-01	None	None	1.85E-04	*included in Specified PAHs*
Dibenz(a,h)anthracene	5.96E-05	3.46E-01	None	None	1.73E-04	*included in Specified PAHs*
Ethylbenzene	4.54E-02	2.63E+02	None	4.30E+01	1.32E-01	
Formaldehyde	1.18E+00	6.78E+03	1.20E-01	1.80E+01	3.39E+00	
Hexane	6.56E-01	3.81E+03	None	2.70E+05	1.90E+00	
Indeno(1,2,3-cd)pyrene	5.96E-05	3.46E-01	None	None	1.73E-04	*included in Specified PAHs*
Naphthalene	4.21E-03	2.44E+01	None	None	1.22E-02	
Propylene	1.95E+00	1.13E+04	None	1.20E+05	5.67E+00	not a HAP
Propylene Oxide	1.21E-01	7.03E+02	6.80E+00	2.90E+01	3.51E-01	
Toluene	1.81E-01	1.05E+03	8.20E+01	1.20E+04	5.23E-01	
Xylene (Total)	6.61E-02	3.84E+02	4.90E+01	2.70E+04	1.92E-01	
Sulfuric Acid Mist (H2SO4)	1.73E+00	6.86E+03	2.60E-01	3.90E+01	3.43E+00	not a HAP
Benzo(a)pyrene equivalents	1.16E-04	6.72E-01	None	6.90E-03	3.36E-04	*included in Specified PAHs*
Specified PAHs	3.32E-04	1.93E+00	None	None	9.63E-04	
Total HAPs					7.750	
Total Toxic Air Contaminants and HAPs					55.31	

Notes:
PAH impacts are evaluated as Benzo(a)pyrene equivalents.

	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

Toxic Air Contaminant Emissions from Normal Operations (8760 hours/year)

Toxic Air Contaminant	EF lb/MMBtu	Per Turbine Firing Rate MMBtu/hour	Per Turbine Firing Rate MMBtu/year	Per Turbine lb/hour	Per Turbine lb/year
1,3-Butadiene	1.25E-07	1085	9504600	1.35E-04	1.18E+00
Acetaldehyde	1.34E-04			1.46E-01	1.28E+03
Acrolein	1.85E-05			2.01E-02	1.76E+02
Ammonia	0.00E+00			0.00E+00	0.00E+00
Benzene	1.30E-05			1.41E-02	1.24E+02
Benzo(a)anthracene	2.22E-08			2.40E-05	2.11E-01
Benzo(a)pyrene	1.36E-08			1.48E-05	1.30E-01
Benzo(b)fluoranthene	1.11E-08			1.20E-05	1.05E-01
Benzo(k)fluoranthene	1.08E-08			1.17E-05	1.03E-01
Chrysene	2.47E-08			2.68E-05	2.35E-01
Dibenz(a,h)anthracene	2.30E-08			2.50E-05	2.19E-01
Ethylbenzene	1.75E-05			1.90E-02	1.67E+02
Formaldehyde	4.50E-04			4.88E-01	4.28E+03
Hexane	2.54E-04			2.76E-01	2.41E+03
Indeno(1,2,3-cd)pyrene	2.30E-08			2.50E-05	2.19E-01
Naphthalene	1.63E-06			1.77E-03	1.55E+01
Propylene	7.56E-04			8.20E-01	7.18E+03
Propylene Oxide	4.69E-05			5.08E-02	4.45E+02
Toluene	6.96E-05			7.55E-02	6.62E+02
Xylene (Total)	2.56E-05			2.78E-02	2.43E+02
Sulfuric Acid Mist (H2SO4)	3.57E-04			3.87E-01	3.39E+03
Benzo(a)pyrene equivalents	4.48E-08			4.86E-05	4.26E-01
Specified PAHs				1.39E-04	1.22E+00

Emission Factors from ARB CATEF database
Formaldehyde emissions reflect 50% destruction efficiency due to oxidation catalyst.

	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

S-100 has no SCR and therefore no ammonia slip emissions.

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

Higher Heating Value, Btu/cf	1020
Fuel Usage MMBtu/hr	104
Fuel Usage MMBtu/yr	205400

Emission Estimate for Natural Gas Fired Boiler S-101 and S-102, 3950 hours per year for both boilers combined

AP-42 Emission Factors from Table 1.4-3 (7/98), See Policy for Toxic Air Contaminants from Misc. Natural Gas Sources

Toxic Air Contaminant	Emission Factor (lb/MMcf)	Emission Factor (lb/MMBtu)	One Boiler Emissions (lb/hr)	One Boiler Emissions (lb/yr)	Both Boiler Emissions (lb/hr)	Both Boiler Emissions (lb/yr)
Benzene	2.10E-03	2.06E-06	2.14E-04	4.23E-01	4.28E-04	8.46E-01
Formaldehyde	7.50E-02	7.35E-05	7.65E-03	1.51E+01	1.53E-02	3.02E+01
Toluene	3.40E-03	3.33E-06	3.47E-04	6.85E-01	6.93E-04	1.37E+00

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

Toxic Air Contaminant Emissions from Normal Operations (5,494,300 MMBtu/year for all 3 turbines)

Toxic Air Contaminant	EF lb/MMBtu	Per Turbine Firing Rate MMBtu/hour	Per Turbine Firing Rate MMBtu/year	Per Turbine lb/hour	Per Turbine lb/year	Total CT lb/hour	Total CT lb/year
1,3-Butadiene	1.25E-07	500	1831433.3	6.23E-05	2.28E-01	1.87E-04	6.84E-01
Acetaldehyde	1.34E-04			6.72E-02	2.46E+02	2.01E-01	7.38E+02
Acrolein	1.85E-05			9.26E-03	3.39E+01	2.78E-02	1.02E+02
Ammonia	1.40E-02			7.00E+00	2.56E+04	2.10E+01	7.69E+04
Benzene	1.30E-05			6.52E-03	2.39E+01	1.96E-02	7.16E+01
Benzo(a)anthracene	2.22E-08			1.11E-05	4.06E-02	3.32E-05	1.22E-01
Benzo(a)pyrene	1.36E-08			6.81E-06	2.50E-02	2.04E-05	7.49E-02
Benzo(b)fluoranthene	1.11E-08			5.54E-06	2.03E-02	1.66E-05	6.09E-02
Benzo(k)fluoranthene	1.08E-08			5.39E-06	1.98E-02	1.62E-05	5.93E-02
Chrysene	2.47E-08			1.24E-05	4.52E-02	3.71E-05	1.36E-01
Dibenz(a,h)anthracene	2.30E-08			1.15E-05	4.22E-02	3.46E-05	1.27E-01
Ethylbenzene	1.75E-05			8.77E-03	3.21E+01	2.63E-02	9.64E+01
Formaldehyde	4.50E-04			2.25E-01	8.24E+02	6.75E-01	2.47E+03
Hexane	2.54E-04			1.27E-01	4.65E+02	3.81E-01	1.40E+03
Indeno(1,2,3-cd)pyrene	2.30E-08			1.15E-05	4.22E-02	3.46E-05	1.27E-01
Naphthalene	1.63E-06			8.14E-04	2.98E+00	2.44E-03	8.94E+00
Propylene	7.56E-04			3.78E-01	1.38E+03	1.13E+00	4.15E+03
Propylene Oxide	4.69E-05			2.34E-02	8.58E+01	7.03E-02	2.57E+02
Toluene	6.96E-05			3.48E-02	1.27E+02	1.04E-01	3.82E+02
Xylene (Total)	2.56E-05			1.28E-02	4.69E+01	3.84E-02	1.41E+02
Sulfuric Acid Mist (H2SO4)	5.90E-04			2.95E-01	1.08E+03	8.84E-01	3.24E+03
Benzo(a)pyrene equivalents	4.48E-08			2.24E-05	8.20E-02	6.72E-05	2.46E-01
Specified PAHs				6.42E-05	2.35E-01	1.93E-04	7.06E-01

Emission Factors from ARB CATEF database
Formaldehyde emissions reflect 50% destruction efficiency due to oxidation catalyst.

	Equivalency Factor
Benzo(a)anthracene	0.1
Benzo(a)pyrene	1
Benzo(b)fluoranthrene	0.1
Benzo(k)fluoranthene	0.1
Chrysene	0.01
Dibenz(a,h)anthracene	1.05
Indeno(1,2,3-cd)pyrene	0.1

Ammonia lb/MMBtu = ppm x 1/molar volume x MW x Fd x 20.9/(20.9 - %O2)

ppm = 10 ppm @15%O2 limit
molar volume = 386.8 dscf/lbmol @ 14.696 psia, 70 deg. F
MW = molecular weight, lb/lb-mol
Fd = 8743 dscf/MMBtu for Natural Gas @ 70 deg. F

Ammonia lb/MMBtu = 10 E-06 ft3 of NH3/ft3 stack gas x 1/386.8 dscf/lb-mol x 17 lb/lb-mol x 8743 dscf/MMBtu x 20.9/(20.9 - 15)
Ammonia lb/MMBtu = 0.014

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

California Air Resources Board, CATEF Gas Turbine TAC Emission Factors

ID	System Type	Material Type	SCC	APC Device	Other Description	CAS	Substance	Max Emission factor	Mean	Median	Unit	lb/MMBtu
4544	Turbine	Natural gas	20200203	None	None	106-99-0	1,3-Butadiene	1.33E-04	1.27E-04	1.24E-04	lbs/MMcf	1.25E-07
4569	Turbine	Natural gas	20200203	None	None	75-07-0	Acetaldehyde	5.11E-01	1.37E-01	5.38E-02	lbs/MMcf	1.34E-04
4574	Turbine	Natural gas	20200203	None	None	107-02-8	Acrolein	6.93E-02	1.89E-02	1.09E-02	lbs/MMcf	1.85E-05
4586	Turbine	Natural gas	20200203	None	None	71-43-2	Benzene	4.72E-02	1.33E-02	1.01E-02	lbs/MMcf	1.30E-05
4594	Turbine	Natural gas	20200203	None	None	56-55-6	Benzo(a)anthracene	1.34E-04	2.26E-05	3.61E-06	lbs/MMcf	2.22E-08
4599	Turbine	Natural gas	20200203	None	None	50-32-8	Benzo(a)pyrene	9.16E-05	1.39E-05	2.57E-06	lbs/MMcf	1.36E-08
4604	Turbine	Natural gas	20200203	None	None	205-99-2	Benzo(b)fluoranthene	6.72E-05	1.13E-05	2.87E-06	lbs/MMcf	1.11E-08
4619	Turbine	Natural gas	20200203	None	None	207-08-9	Benzo(k)fluoranthene	6.72E-05	1.10E-05	2.87E-06	lbs/MMcf	1.08E-08
4624	Turbine	Natural gas	20200203	None	None	218-01-9	Chrysene	1.50E-04	2.52E-05	4.99E-06	lbs/MMcf	2.47E-08
4629	Turbine	Natural gas	20200203	None	None	53-70-3	Dibenz(a,h)anthracene	1.34E-04	2.35E-05	3.03E-06	lbs/MMcf	2.30E-08
4634	Turbine	Natural gas	20200203	None	None	100-41-4	Ethylbenzene	5.70E-02	1.79E-02	9.74E-03	lbs/MMcf	1.75E-05
4649	Turbine	Natural gas	20200203	None	None	50-00-0	Formaldehyde	6.87E+00	9.17E-01	1.12E-01	lbs/MMcf	8.99E-04
4654	Turbine	Natural gas	20200203	None	None	110-54-3	Hexane	3.82E-01	2.59E-01	2.19E-01	lbs/MMcf	2.54E-04
4659	Turbine	Natural gas	20200203	None	None	193-39-5	Indeno(1,2,3-cd)pyrene	1.34E-04	2.35E-05	2.87E-06	lbs/MMcf	2.30E-08
4664	Turbine	Natural gas	20200203	None	None	91-20-3	Naphthalene	7.88E-03	1.66E-03	9.26E-04	lbs/MMcf	1.63E-06
4679	Turbine	Natural gas	20200203	None	None	115-07-1	Propylene	2.00E+00	7.71E-01	5.71E-01	lbs/MMcf	7.56E-04
4684	Turbine	Natural gas	20200203	None	None	75-56-9	Propylene Oxide	5.87E-02	4.78E-02	4.48E-02	lbs/MMcf	4.69E-05
4694	Turbine	Natural gas	20200203	None	None	108-88-3	Toluene	1.68E-01	7.10E-02	5.91E-02	lbs/MMcf	6.96E-05
4709	Turbine	Natural gas	20200203	None	None	1330-20-7	Xylene (Total)	6.26E-02	2.61E-02	1.93E-02	lbs/MMcf	2.56E-05

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

H2SO4 Estimate

Worst Case lb/hr

1 grain Sulfur/100 scf

lb S/MMBtu = 1 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.0014 lb S/MMBtu

lb SO2/MMBtu = 0.0014 lb S/MMBtu x 64/32 = 0.0028 lb SO2/MMBtu

Worst Case Annual Average lb/hour assume 55% SO2 converts to H2SO4 (See Application 17182 Marsh Landing Record)

lb H2SO4/MMBtu = 0.0028 lb SO2/MMBtu x 98/64 x 0.55 = 0.002358 lb H2SO4/MMBtu

Simple Cycle Turbine lb/hr H2SO4 = 500 MMBtu/hour x 0.002358 lb H2SO4/MMBtu = 1.18 lb/hour per turbine

Annual Average assume 55% SO2 converts to H2SO4

0.25 grain Sulfur/100 scf

lb S/MMBtu = 0.25 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.00035 lb S/MMBtu

lb SO2/MMBtu = 0.00035 lb S/MMBtu x 64/32 = 0.0007 lb SO2/MMBtu

Worst Case Annual Average lb/hour assume 55% SO2 converts to H2SO4 (See Application 17182 Marsh Landing Record)

lb H2SO4/MMBtu = 0.0007 lb SO2/MMBtu x 98/64 x 0.55 = 0.00059 lb H2SO4/MMBtu

Simple Cycle Turbine lb/hr H2SO4 = 500 MMBtu/hour x 0.00059 lb H2SO4/MMBtu = 0.295 lb/hour per turbine

Total H2SO4 = 0.295 lb/hour x 10,988.6 hour/year = 3241.6 lb/year, 1.62 ton/year

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

H_2SO_4 Estimate

Worst Case lb/hr

1 grain Sulfur/100 scf

lb S/MMBtu = 1 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.0014 lb S/MMBtu

lb SO_2/MMBtu = 0.0014 lb S/MMBtu x 64/32 = 0.0028 lb SO_2/MMBtu

Worst Case Annual Average lb/hour assume 33.3% SO_2 converts to H_2SO_4 (See Guidance from National Park Service)
http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm

lb H_2SO_4/MMBtu = 0.0028 lb SO_2/MMBtu x 98/64 x 0.333 = 0.00143 lb H_2SO_4/MMBtu

Simple Cycle Turbine lb/hr H_2SO_4 = 1085 MMBtu/hour x 0.00143 lb H_2SO_4/MMBtu = 1.55 lb/hour per turbine

Annual Average assume 33.3% SO_2 converts to H_2SO_4

0.25 grain Sulfur/100 scf

lb S/MMBtu = 0.25 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.00035 lb S/MMBtu

lb SO_2/MMBtu = 0.00035 lb S/MMBtu x 64/32 = 0.0007 lb SO_2/MMBtu

Worst Case Annual Average lb/hour assume 33.3% SO_2 converts to H_2SO_4 (See Guidance from National Park Service)
http://www.nature.nps.gov/air/Permits/ect/ectGasFiredCT.cfm

lb H_2SO_4/MMBtu = 0.0007 lb SO_2/MMBtu x 98/64 x 0.333 = 0.000357 lb H_2SO_4/MMBtu

Simple Cycle Turbine lb/hr H_2SO_4 = 1085 MMBtu/hour x 0.000357 lb H_2SO_4/MMBtu = 0.387 lb/hour per turbine, 8760 hours/year

Total H_2SO_4 = 0.387 lb/hour x 8760 hour/year = 3390.1 lb/year, 1.70 ton/year

Application No. 22569
Plant No. 11180
Calpine Gilroy
BAAQMD December 2011

H2SO4 Estimate

Worst Case lb/hr

1 grain Sulfur/100 scf

lb S/MMBtu = 1 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.0014 lb S/MMBtu

lb SO2/MMBtu = 0.0014 lb S/MMBtu x 64/32 = 0.0028 lb SO2/MMBtu

Worst Case lb/hour assume 5% SO2 converts to H2SO4

lb H2SO4/MMBtu = 0.0028 lb SO2/MMBtu x 98/64 x 0.05 = 0.000214 lb H2SO4/MMBtu

Auxilliary Boiler lb/hr H2SO4 = 1085 MMBtu/hour x 0.000214 lb H2SO4/MMBtu = 0.23 lb/hour per boiler

Annual Average assume 5% SO2 converts to H2SO4

0.25 grain Sulfur/100 scf

lb S/MMBtu = 0.25 grain S/100 scf x lb/7000 grains x scf/1020 Btu x 1E06 Btu/MMBtu = 0.00035 lb S/MMBtu

lb SO2/MMBtu = 0.00035 lb S/MMBtu x 64/32 = 0.0007 lb SO2/MMBtu

Worst Case Annual Average lb/hour assume 5% SO2 converts to H2SO4 (No Oxidation Catalyst)

lb H2SO4/MMBtu = 0.0007 lb SO2/MMBtu x 98/64 x 0.05 = 0.0000536 lb H2SO4/MMBtu

Auxilliary Boiler lb/hr H2SO4 = 1085 MMBtu/hour x 0.0000536 lb H2SO4/MMBtu = 0.058 lb/hour per boiler

Total H2SO4 both boilers = 0.058 lb/hour x 3950 hour/year = 229.1 lb/year, 0.115 ton/year