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:
P.O. Box 1764
Gilroy, CA 95021

Application Engineer:
Krishnaswamy R. Bhagavan

Site Engineer:
Dennis T. Jang

Application:
6748

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, Part 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, of 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 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.

<u>Title V Permitting History</u>

Please note that Table II-A, Table II-B and Section VI of the renewed permit contain the sources, abatement devices and permit conditions referenced in the following discussion.

An initial Title V permit was issued by the District to Calpine Gilroy Cogen, L.P. on May 12, 1998 for sources S-100, S-101 and S-102 and an abatement device A-100. On December 18, 1998, a significant revision of the permit was issued (Application 18872). The change involved replacing an existing permit condition relating to the destruction efficiency of the oxidation catalyst, A-100, with a new carbon monoxide mass concentration emission limit for exhaust emissions from the turbine (i.e. parts 3.a. and 3.b. of permit condition # 2780 were replaced with parts 3.a. through 3.g. in the revised permit condition.)

On July 26, 2000, a minor revision of the permit was issued (Application 445). On October 21, 2001, a significant revision was issued (Application 2686). The company received permission to install three 45 MW natural gas fired simple cycle turbines – sources 3 through 5, dispatched under contract with the California Independent System Operator to supply electricity during times of peak summer and winter demand. Criteria pollutant emissions are abated by a selective catalytic reduction system in conjunction with an oxidation catalyst. In addition to the above, the cooling tower, S-104, which was excluded from previously issued Title V permit's because it was exempt from District permitting per Regulations 2-1-128.4 and 2-1-319.1 was deemed a significant source and was included in the revised Title V permit. The following sources and abatement devices were added to the permit: S-3, S-4, S-5, S-104, A-3, A-4, A-5, A-6, A-7, and A-8.

Calpine Gilroy Cogen, L.P and Calpine Gilroy Energy Center, L.L.C submitted application 6748 on December 2, 2002 for renewal of their Title V permit. Although the current permit expires on May 12, 2003, it continues in force until the District takes final action on the permit renewal.

B. Facility Description

Calpine Gilroy Cogen, L.P, a cogeneration facility, and Calpine Gilroy Energy Center, L.L.C, a peaking facility, are collocated on Pacheco Pass Highway (Highway 152), southeast of the business district of Gilroy in Santa Clara County, California.

The cogeneration facility “Calpine Gilroy Cogen, L.P” produces both electricity for sale to Pacific Gas & Electric Company (PG&E) and steam for sale to ConAgra Foods from a combined cycle gas turbine. The following permitted sources and abatement devices listed in Tables II-A and II-B of the permit are located at Calpine Gilroy Cogen, L.P: S-100, S-101, S-102, S-104, and A-100. Sources S-100, S-101, S-102 and S-104 were issued an Authority to Construct (AC) and a Permit to Operate (PO) under Application 30331 in April 1985 and June 1988, respectively. Abatement device A-100 was issued an AC and PO under Application 1530 in December 1988 and June 1990, respectively.

The peaking facility “Calpine Gilroy Energy Center, L.L.C” is located south of the cogeneration facility, and produces electricity at peak demand times under contract with the California Department of Water Resources (DWR), or for sale to PG&E, from three simple cycle gas turbines. The following permitted sources and abatement devices listed in Tables II-A and II-B of the permit are located at Calpine Gilroy Energy Center, L.L.C: S-3, S-4, S-5, A-3, A-4, A-5, A-6, A-7 and A-8. The above sources and abatement devices were issued an AC and PO under Application 2686 in June 2001 and June 2002, respectively. Sources S-3 and S-4 achieved first fire in October 2001 and source S-5 achieved first fire in February 2002. The Commercial On-Line Date (COD) i.e. date when turbines were ready for routine operation was April 2002.

Following is a description of the sources at Calpine Gilroy Cogen, L.P and Calpine Gilroy Energy Center, L.L.C.

Calpine Gilroy Cogen, L.P

<u>S-100 Gas Turbine Generator:</u>

S-100 is a General Electric (GE) Frame 7 industrial *combined-cycle* turbine that uses natural gas as its only fuel source. The turbine drives an electric generator with a hot end drive (i.e. shaft that drives the electric generator passes through the hot exhaust of the turbine). Exhaust gases from the turbine are sent to a Heat Recovery Steam Generator (HRSG), which consists of large bundles of tubes made out of highly conductive materials that are collectively referred to as heat exchangers. Feed water pumps continually run De-Ionized (DI) through the heat exchangers in the HRSG. The HRSG does not have supplemental fuel firing (i.e. duct burners). The superheated steam formed in the HRSG is injected into the steam turbine downstream of it. The steam turbine is a two-stage (high pressure and low pressure) generator. As the superheated steam expands through the steam turbine, its temperature and pressure decrease and energy is transferred to the turbine, making it to rotate. Some amount of steam that completes its run through the high-pressure section of the steam turbine is extracted for use by ConAgra foods in their food drying process. The remaining steam is sent to the low-pressure section of the steam turbine.

Combustion turbines such as S-100 that compress combustion air are sensitive to changes in ambient temperature - both the compressor capacity and the efficiency of the turbine decrease with increasing ambient temperatures. Specifically, the power demand of the compressor section of the turbine is approximately proportional to the absolute temperature of the inlet air. This in turn makes the efficiency of the turbine proportional to the inverse of the absolute temperature entering the compressor section.

To counteract the warm ambient air degradation and increase S-100's power output, Calpine Gilroy Cogen, L.P employs one of two inlet air-cooling systems at any given time. The first system is a fogging system. Here DI water is sprayed into the inlet air stream to cool the inlet air via evaporation. The second system is called the Thermal Energy Storage System (TESS). The TESS uses a refrigeration unit to make ice in the off-peak hours when electric prices are low. During peak price hours, the ice is used - via a chilled water loop, to cool the inlet air. The TESS system is drastically affected by the plant's market dispatch. If the plant does not run overnight, the TESS cannot be 'recharged', and fogging will be the only cooling system that will be used.

Criteria pollutant emissions of NOx and CO from S-100 are controlled with the use of steam injection and an oxidation catalyst, respectively. Steam is injected into the combustion chamber of S-100, which in turn reduces the amount of NOx produced by the turbine. The oxidation catalyst, A-100, oxidizes the CO emissions from the turbine to CO2 and water.

S-101 and S-102 Auxiliary Boilers:
Two identical Nebraska, NSE68 natural gas fired boilers are used to supply steam to ConAgra foods when S-100 is not operating. This is especially the case during the harvest season, when ConAgra operates continually i.e. 24 hours / day, 7 days / week. S-100 only operates when the market conditions are profitable. Therefore the auxiliary boilers are used to supply the necessary steam load when the turbine is not operating. In addition, both boilers supply seal steam to S-100 during turbine startup.

S-104 Counter-flow Design Cooling Tower:
The cooling tower is the cooling source for the main condenser. The cooling water loop is used to condensate the steam from the steam turbine, so it can be returned to the HRSG. The DI water used in the HRSG is higher purity water than the water used in the cooling tower. The cooling tower uses well water, while the steam loop uses DI water. After the water from the cooling tower is used to condense the steam, it returns to the cooling tower and is sprayed into the cells. Fans on the tower cause air to counter-flow with the water, cooling the return water by evaporation. The water falls into the cooling tower basin and is reused in the cooling loop.

Calpine Gilroy Energy Center, L.L.C

S-3, S-4, and S-5 Gas Turbine Generators:

Sources 3 through 5 are made up of three individual *simple cycle* GE LM6000PC turbines that use natural gas as their only fuel source. The GE LM6000 is an aeroderivative turbine - it was developed from GE's aircraft engine design for 747 aircraft engines. Sources 3 through 5 are collectively referred to as 'Peakers'. They are used to generate electricity at times of peak electricity demand. Peakers have a very short start-up time – less than 30 minutes. However, there is a trade-off in their efficiency due to their ability to start quickly and run for short periods of time. Each turbine turns a generator with a cold end drive (i.e. the shaft that turns the generator does not pass through the exhaust end of the turbine).

As previously discussed under "S-100" in the preceding paragraphs, combustion turbines such as the peakers are sensitive to changes in ambient temperature. To counteract the warm ambient air degradation, the GE LM6000 incorporates a system known as Enhanced Spray Intercooling (ESPRINT) to increase power output from the peakers. The ESPRINT system injects DI water into the inlet of the low-pressure compressor, or the inlet of the high-pressure compressor depending on the ambient temperature. Each turbine incorporates a closed water loop that can be either heated or chilled to help control the inlet air temperature i.e. reduce turbine inlet air temperature during summer, and heat the turbine inlet air during winter to prevent icing.

The following three types of emission controls are used on each turbine:

- Water injection: Similar to NOx steam injection previously discussed under "S-100", DI water is injected into the combustion chamber of each turbine to control NOx emissions.
- Selective Catalytic Reduction (SCR): Sources 3 through 5, are equipped with abatement devices i.e. SCRs, A-4, A-6 and A-8, respectively. The SCR process works by injecting ammonia into the turbine exhaust gas, in the presence of a catalyst. The ammonia reacts with the NOx emissions in the turbine exhaust gas to form nitrogen and water.
- Oxidation Catalyst (OC): Sources 3 through 5, are equipped with abatement devices i.e. OCs, A-3, A-5 and A-7, respectively, downstream of SCRs A-4, A-6 and A-8, respectively. The CO emissions from the turbines are oxidized by the OC to CO2 and water.

Aqueous and anhydrous ammonia are the two types of ammonia typically used for ammonia injection in SCRs, with the aqueous form being the safer of the two types. The SCRs that abate the "Peakers" (sources S-3 through S-5) at Calpine use a 19% aqueous ammonia solution.

A health risk assessment performed by the District using air dispersion modeling under BAAQMD Application 2686, assumed a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the SCRs, estimated an acute hazard index of 0.006 and a chronic hazard index of 0.0096. In accordance with the District's Toxic Risk Management Policy it was determined that the toxic impact of the ammonia slip was insignificant.

C. Permit Content

The legal and factual basis for the permit follows. The permit sections are described in the order that they are presented in the permit. Changes to the standard permit text will be made since the initial Title V Permit for this site was issued. These changes are reflected in the new proposed permit in strikeout/underline format.

In a letter dated November 2, 2001, Sierra Research – air consultants to Calpine Gilroy Cogen, L.P., recommended several changes to Calpine Gilroy Cogen, L.P.'s Title V permit. The District will make the following changes in the proposed Title V permit renewal:

- Changed the facility name from Calpine Gilroy Cogen, L.P. to Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C. Changed the type of facility from cogeneration to cogeneration plant and power plant. (administrative change)
- Since turbine emissions are a function of their heat input rate as opposed to their power generating rate, the nominal turbine power generating capacities for sources 3, 4, 5 and 100, previously listed under the "Capacity" column in Table II-A, have now been listed under the "Description" column. (administrative change)
- The "Make or Type" and "Capacity" of the cooling tower S-104 were incorrect and inconsistent with actual operations at the plant. In order to make the permit consistent with plant operations the "Make or Type" and "Capacity" has been changed from "two-cell" and "1.2 MM gallons/hr" to "three-cell" and "1.44 MM gallons/hr", respectively.
- To correct a typographical error, the "Applicable Emission Limits and Compliance Monitoring Requirements" table number for sources 101 and 102 that was previously numbered as Table VII-B has been renumbered to Table VII-C. (administrative change)

In addition to the above, the District will make the following administrative changes in the renewed Title V permit in light of two e-mails dated June 6, 2003 and August 30, 2004, and a letter dated July 21, 2003 from Calpine Gilroy Cogen, L.P and Calpine Gilroy Energy Center, L.L.C:

- the Facility Contact will be changed from Brian Martin to Maria Barroso, Compliance Manager, per an e-mail received on August 30, 2004.
- the Responsible Official (RO) and RO designation will be changed from Robert McCaffrey, General Manager to Roger Morales, Operations Manager.

Lastly, "Performance Specifications" requirements contained in 40 CFR 60, Appendix B and "Quality Assurance Procedures" contained in 40 VFR 60, Appendix F will be incorporated in Tables IV-A through IV-C.

I. Standard Conditions

This section contains administrative requirements and conditions that apply to all facilities. If the Title IV (Acid Rain) requirements for certain 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.

As previously discussed in the "Facility Description" under "Calpine Gilroy Energy Center, L.L.C", the storage and transport of the 19% aqueous ammonia used in the SCRs abating the "Peakers" is subject to 40 CFR 68 "Chemical Accident Prevention Provisions", Subpart G "Risk Management Plan". 40 CFR 68, Subpart G and standard condition "I.K. Accidental Release" in the permit require facilities such as Calpine to maintain a RMP and implement a Risk Management Program to prevent accidental releases of substances such as ammonia. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases.

Source S-100 at Calpine Gilroy Cogen, L.P was previously exempt from the Acid Rain Program per 40 CFR 72.6(b)(5). As of October 1, 2004, source S-100 is no longer exempt from the Acid Rain Program because it does not meet the exemption criteria under the afore-referenced section. On February 5, 2005, Calpine submitted an Acid Rain application to the District for S-100. In light of the above, standard condition "I.L. Conditions to Implement Regulation 2, Rule 7, Acid Rain" in the permit will be modified accordingly.

Other Changes to permit:

The deadline for allowances in Standard Condition I.L.1 has been modified to reflect changes in 40 CFR 72.

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., S-24).

Permitted sources are those sources that require a BAAQMD operating permit pursuant to BAAQMD Rule 2-1-302.

Significant sources are those sources that have a potential to emit of more than 2 tons of a "regulated air pollutant," as defined in BAAQMD Rule 2-6-222, per year or 400 pounds of a "hazardous air pollutant," as defined in BAAQMD Rule 2-6-210, per year.

All abatement (control) devices that control permitted or significant sources are listed. Each abatement device whose primary function is to reduce emissions is identified by an A and a number (e.g., A-24). If a source is also an abatement device, such as when an engine controls VOC emissions, it will be listed in the abatement device table but will have an "S" number. An abatement device may also be a source (such as a thermal oxidizer that burns fuel) of secondary emissions. If the primary function of a device is to control emissions, it is considered an abatement (or "A") device. If the primary function of a device is a non-control function, the device is considered to be a source (or "S").

The equipment section is considered to be part of the facility description. It contains information that is necessary for applicability determinations, such as fuel types, contents or sizes of tanks, etc. This information is part of the factual basis of the permit.

Each of the permitted sources has previously been issued a permit to operate pursuant to the requirements of BAAQMD Regulation 2, Permits. These permits are issued in accordance with state law and the District's regulations. The capacities in the permitted sources table are the maximum allowable capacities for each source, pursuant to Standard Condition I.J and Regulation 2-1-403.

As previously discussed in Section I.A. "Background" under "Title V Permitting History", the Cooling Tower, S-104, though exempt from District permitting per Regulations 2-1-128.4 and 2-1-319.1 was deemed a significant source of particulate matter emissions in light of revisions made to Regulation 2-6-405.6 on May 2, 2001 by the District. In accordance with revisions made to Regulation 2-6-405.6 on May 2, 2001, S-104 is no longer excluded from the Title V permit, regardless of any exemption from District permitting. Therefore, the applicable requirements for the Cooling Tower will be incorporated in the proposed renewal permit and S-104 will be added to the facility source list.

The following sources and abatement devices were included in the initial Title V permit that was issued to Calpine Gilroy Cogen, L.P. on May 12, 1998: S-100, S-101, S-102, and A-100. On October 21, 2001, the following sources and abatement devices were added to the initial Title V permit as a result of a significant modification (Application 2686): S-3, S-4, S-5, S-104, A-3, A-4, A-5, A-6, A-7, and A-8.

Changes to the permit:

Source S-6 "Emergency Standby Fire Pump: Diesel Engine" will be added to the equipment list. The source has been in operation at the facility since 1986 and was previously exempt from permit requirements. The source became subject to a permit to operate in 2001 due to a change in District permit rules. The permit status for the source was changed under Application 9805 in June 2004. The engineering evaluation for application 9805 is attached as Appendix C. The source will be included into the proposed Title V renewal permit. Please refer to Tables II-A, IV-E, and VII-E.

District permit applications not included in this proposed permit:

None

Emissions Change at the Facility:

No new sources will be permitted at the plant since October 21, 2001. Therefore, there has been no change in emissions at the plant.

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. If a generally applicable requirement applies specifically to a source that is permitted or significant, the standard will also appear in Section IV and the monitoring for that requirement will appear in Sections IV and VII of the permit. Parts of this section apply to all facilities (e.g., particulate, architectural coating, odorous substance, and sandblasting standards). In addition, standards that apply to insignificant or unpermitted sources at a facility (e.g., refrigeration units that use more than 50 pounds of an ozone-depleting compound) are placed in this section.

Changes to permit:

Section III has been modified to say that SIP standards are now found on EPA's website and are not included as part of the 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 will be 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.

Section IV of the permit contains citations to all of the applicable requirements. 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.

Changes to the permit:

Changes to Section IV are primarily routine and include the updating of text to the current standard, updating the applicable requirements tables to reflect the current versions of the cited regulations, addition and deletion of applicable requirements tables for sources that will be added as discussed in Part II above.

Regulation 1 requirements will be added to Tables IV-A, IV-B, and IV-C in the proposed Title V renewal permit.

Complex Applicability Determinations:

New Source Performance Standards (NSPS):

Sources S-3, S-4, S-5, S-100, S-101 and S-102 are subject to the "General Provisions" requirements in 40 CFR 60, Subpart A which provides the general regulatory framework for NSPS regulations. The three simple cycle turbines, S-3 through S-5, and the combined cycle turbine S-100 are subject to the NOx and SO2 requirements contained in 40 CFR 60, Subpart GG "Standards of Performance for Stationary Gas Turbines", because the turbines were constructed after October 3, 1977 and the heat input at peak load of each individual turbine is greater than 10 MMBTU/hr. The two auxiliary boilers, S-101 and S-102, are subject to 40 CFR 60, Subpart Db (NSPS Db) "Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" because the rule applies to any steam generating unit constructed between June 19, 1984 through June 19, 1986 with an individual heat input capacity greater 100 MMBTU/hr.

National Emission Standards for Hazardous Air Pollutants (NESHAPs):

The facility does not emit nor has the potential to emit any single HAP at a rate of 10 tons (9.07 megagrams) or more per year or any combination of HAP at a rate of 25 tons (22.68 megagrams) or more per year. Therefore, the facility is not subject to the 40 CFR 63 Maximum Achievable Control Technology (MACT) standards for combustion turbines and/or the Industrial, Commercial, and Institutional Boilers and Process Heaters MACT standards. Please refer to Table's A, B, and C.

Table A
HAP Emissions from Gas Turbines

Pollutant	Emission Factor (lb/MMBTU)	Annual Emissions per Peaker (lb/year)	Annual Emissions for three Peaker's (lb/year)	Annual Emissions for Cogen (lb/year)	Combined Annual Emissions from Peakers & Cogen (lb/year)	Combined Annual Emissions from Peakers & Cogen (TPY)
1,3-Butadiene	4.30E-07	1.76E+00	5.28E+00	4.09E+00	9.37E+00	4.69E-03
Acetaldehyde	4.00E-05	1.64E+02	4.92E+02	3.80E+02	8.72E+02	4.36E-01
Acrolein	6.40E-06	2.62E+01	7.86E+01	6.08E+01	1.39E+02	6.97E-02
Benzene	1.20E-05	4.92E+01	1.47E+02	1.14E+02	2.62E+02	1.31E-01
Ethylbenzene	3.20E-05	1.31E+02	3.93E+02	3.04E+02	6.97E+02	3.49E-01
Formaldehyde	7.10E-04	2.91E+03	8.72E+03	6.75E+03	1.55E+04	7.74E+00
Napthalene	1.30E-06	5.33E+00	1.60E+01	1.24E+01	2.83E+01	1.42E-02
PAH	2.20E-06	9.01E+00	2.70E+01	2.09E+01	4.79E+01	2.40E-02
Propylene Oxide	2.90E-05	1.19E+02	3.56E+02	2.76E+02	6.32E+02	3.16E-01
Toluene	1.30E-04	5.33E+02	1.60E+03	1.24E+03	2.83E+03	1.42E+00
Xylenes	6.40E-05	2.62E+02	7.86E+02	6.08E+02	1.39E+03	6.97E-01

Note:
1. Emission factors for HAPs excerpted from AP-42, Table 3.1-3, April 2000 version

Table B
HAP Emissions from Auxiliary Boilers

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBTU)	Annual Emissions per Aux. Boiler (lb/year)	Annual Emissions for two Aux. Boiler's (lb/year)	Annual Emissions for two Aux. Boiler's (TPY)
2-Methylnaphthalene	2.40E-05	2.35E-08	2.45E-06	4.89E-06	2.45E-09
3-Methylchloranthrene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
7,12-Dimethylbenz(a)anthracene	1.60E-05	1.57E-08	1.63E-06	3.26E-06	1.63E-09
Acenaphthene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Acenaphthylene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Anthracene	2.40E-06	2.35E-09	2.45E-07	4.89E-07	2.45E-10
Arsenic	2.00E-04	1.96E-07	2.04E-05	4.08E-05	2.04E-08

Table B
HAP Emissions from Auxiliary Boilers

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBTU)	Annual Emissions per Aux. Boiler (lb/year)	Annual Emissions for two Aux. Boiler's (lb/year)	Annual Emissions for two Aux. Boiler's (TPY)
Barium	4.40E-03	4.31E-06	4.49E-04	8.97E-04	4.49E-07
Benz(a)anthracene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Benzene	2.10E-03	2.06E-06	2.14E-04	4.28E-04	2.14E-07
Benzo(a)pyrene	1.20E-06	1.18E-09	1.22E-07	2.45E-07	1.22E-10
Benzo(b)fluoranthene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Benzo(g,h,i)perylene	1.20E-06	1.18E-09	1.22E-07	2.45E-07	1.22E-10
Benzo(k)fluoranthene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Beryllium	1.20E-05	1.18E-08	1.22E-06	2.45E-06	1.22E-09
Butane	2.10E+00	2.06E-03	2.14E-01	4.28E-01	2.14E-04
Cadmium	1.10E-03	1.08E-06	1.12E-04	2.24E-04	1.12E-07
Chromium	1.40E-03	1.37E-06	1.43E-04	2.85E-04	1.43E-07
Chrysene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Cobalt	8.40E-05	8.24E-08	8.56E-06	1.71E-05	8.56E-09
Copper	8.50E-04	8.33E-07	8.67E-05	1.73E-04	8.67E-08
Dibenzo(a,h)anthracene	1.20E-06	1.18E-09	1.22E-07	2.45E-07	1.22E-10
Dichlorobenzene	1.20E-03	1.18E-06	1.22E-04	2.45E-04	1.22E-07
Ethane	3.10E+00	3.04E-03	3.16E-01	6.32E-01	3.16E-04
Fluoranthene	3.00E-06	2.94E-09	3.06E-07	6.12E-07	3.06E-10
Fluorene	2.80E-06	2.75E-09	2.85E-07	5.71E-07	2.85E-10
Formaldehyde	7.50E-02	7.35E-05	7.65E-03	1.53E-02	7.65E-06
Hexane	1.80E+00	1.76E-03	1.84E-01	3.67E-01	1.84E-04
Indeno(1,2,3-cd)pyrene	1.80E-06	1.76E-09	1.84E-07	3.67E-07	1.84E-10
Manganese	3.80E-04	3.73E-07	3.87E-05	7.75E-05	3.87E-08
Mercury	2.60E-04	2.55E-07	2.65E-05	5.30E-05	2.65E-08
Molybdenum	1.10E-03	1.08E-06	1.12E-04	2.24E-04	1.12E-07
Naphthalene	6.10E-04	5.98E-07	6.22E-05	1.24E-04	6.22E-08
Nickel	2.10E-03	2.06E-06	2.14E-04	4.28E-04	2.14E-07
Pentane	2.60E+00	2.55E-03	2.65E-01	5.30E-01	2.65E-04
Phenanathrene	1.70E-05	1.67E-08	1.73E-06	3.47E-06	1.73E-09
Propane	1.60E+00	1.57E-03	1.63E-01	3.26E-01	1.63E-04
Pyrene	5.00E-06	4.90E-09	5.10E-07	1.02E-06	5.10E-10
Selenium	2.40E-05	2.35E-08	2.45E-06	4.89E-06	2.45E-09
Toluene	3.40E-03	3.33E-06	3.47E-04	6.93E-04	3.47E-07
Vanadium	2.30E-03	2.25E-06	2.35E-04	4.69E-04	2.35E-07
Zinc	2.90E-02	2.84E-05	2.96E-03	5.91E-03	2.96E-06

Note:
1. Emission factors for HAPs excerpted from AP-42, Table 1.4-3, July 1998 version

Table C
Total HAP Emissions from Gas Turbines & Auxiliary Boilers

Pollutant	Combined Annual Emissions (TPY)
1,3-Butadiene	4.69E-03
Acetaldehyde	4.36E-01
Acrolein	6.97E-02
Benzene	1.31E-01
Ethylbenzene	3.49E-01
Formaldehyde	7.74E+00
Napthalene	1.42E-02
PAH	2.40E-02
Propylene Oxide	3.16E-01
Toluene	1.42E+00
Xylenes	6.97E-01
2-Methylnaphthalene	2.45E-09
3-Methylchloranthrene	1.84E-10
7,12-Dimethylbenz(a)anthracene	1.63E-09
Acenaphthene	1.84E-10
Acenaphthylene	1.84E-10
Anthracene	2.45E-10
Arsenic	2.04E-08
Barium	4.49E-07
Benz(a)anthracene	1.84E-10
Benzo(a)pyrene	1.22E-10
Benzo(b)fluoranthene	1.84E-10
Benzo(g,h,i)perylene	1.22E-10
Benzo(k)fluoranthene	1.84E-10
Beryllium	1.22E-09
Butane	2.14E-04
Cadmium	1.12E-07
Chromium	1.43E-07
Chrysene	1.84E-10
Cobalt	8.56E-09
Copper	8.67E-08
Dibenzo(a,h)anthracene	1.22E-10
Dichlorobenzene	1.22E-07
Ethane	3.16E-04
Fluoranthene	3.06E-10
Fluorene	2.85E-10
Hexane	1.84E-04
Indeno(1,2,3-cd)pyrene	1.84E-10
Manganese	3.87E-08
Mercury	2.65E-08
Molybdenum	1.12E-07
Nickel	2.14E-07

Table C Total HAP Emissions from Gas Turbines & Auxiliary Boilers	
Pollutant	**Combined Annual Emissions (TPY)**
Pentane	2.65E-04
Phenanathrene	1.73E-09
Propane	1.63E-04
Pyrene	5.10E-10
Selenium	2.45E-09
Vanadium	2.35E-07
Zinc	2.96E-06
Total	**11.1955**

Acid Rain:

The facility meets the criteria for a Phase II[1] Acid Rain Facility per the definition in Section 217 of Regulation 2-6 “Major Facility Review”. Specifically, the peaking units which exclusively combust natural gas were installed after November 15, 1990 and are used to generate electricity for sale. The peaking units at the facility are subject to the requirements of Title IV of the federal Clean Air Act outlined in 40 CFR Part 72 “Acid Rain Program” and 40 CFR Part 75 “Continuous Emission Monitoring”. District Regulation 2, Rule 7 “Acid Rain” incorporates by reference the provisions of 40 CFR Part 72 and administers the program through the Title V Operating Permit.

Source S-100 at Calpine Gilroy Cogen, L.P was previously exempt from the Acid Rain Program since it was a *qualifying facility*[2] 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.”

As of October 1, 2004, source S-100 no longer meets the criteria in the afore-referenced definition, because it no longer has one or more qualifying purchase commitments to sell at least 15 percent of its total planned net output capacity. Therefore, S-100 is subject to the Acid Rain Program. On February 2, 2005, Calpine submitted an Acid Rain application to the District for S-100.

Section (b)(2)(vi) in 72.30 "Requirement to Apply" states:
For any source with a unit under §72.6(a)(3)(v), the designated representative shall submit a complete Acid Rain permit application governing such unit before the latter of January 1, 1998 of March 1 of the year following the calendar year in which the facility fails to meet the definition of qualifying facility.

[1] Acid Rain Program period beginning January 1, 2000, and continuing into the future thereafter.
[2] 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.

In light of the above, the applicable requirements for 40 CFR Parts 72 and 75 will be incorporated into Table IV-B. In similar fashion, the monitoring requirements for SO_2, NO_x, and CO_2 contained in 40 CFR Part 75 (Sections 10 and 11) will be incorporated into Tables VII-B.

This project will be subject to the requirements of Title IV of the federal Clean Air Act. The requirements of the Acid Rain Program are outlined in 40 CFR Part 72, 73, and 75. The specifications for the type and operation of continuous emission monitors (CEMs) for pollutants that contribute to the formation of acid rain are given in 40 CFR Part 75.

District Regulation 2, Rule 7 incorporates by reference the provisions of 40 CFR Part 72 and administers the program in concert with the Title V Operating Permits Program (Rule 2-6).

Protection of Stratospheric Ozone:

The Thermal Energy Storage System at the facility uses a refrigeration unit to make ice in the off-peak hours when electric prices are low. During peak price hours, the ice is used - via a chilled water loop, to cool the inlet air. The requirements of 40 CFR 82 "Protection of Stratospheric Ozone" apply to the refrigerants used in cooling systems, and will be incorporated in Table III "Generally Applicable Requirements".

40 CFR Part 64
Compliance Assurance Monitoring (CAM):

A pollutant-specific emissions unit (unit) at a major source that is required to obtain a part 70 (state operating permit) or part 71 (federal operating permit) is subject to CAM if it satisfies all of the following criteria outlined in 40 CFR 64 (a)(1) through (a)(3):

- The unit is subject to an emission limit/standard for the applicable regulated air pollutant; and
- The unit uses a control device to achieve compliance with any such emission limitation or standard; and
- The unit has potential pre-control device emissions of the applicable regulated air pollutant that are equal to or greater than 100% of the amount, in tons per year, required for a source to be classified as a major source.

Units (turbines) at Calpine, meet the above criteria and are therefore subject to CAM[3]. To be in compliance with CAM for NOx emissions, Calpine would have to continuously monitor the water injection rate at the simple cycle turbines or "Peakers" (S-3 through S-5), and the steam injection rate at the combined cycle turbine (S-100). However, 40 CFR 64.2 (b)(1)(vi) exempts Calpine from implementing CAM at the turbines if Calpine's operating permit, issued under the auspices of 40 CFR Part 70 (state operating permit program) or 71 (federal operating permit program), specifies a continuous compliance determination method to demonstrate compliance with federally enforceable emission limitations or standards.

The NOx emissions from the "Peakers" (S-3, S-4, and S-5) are controlled by water injection and are abated by Selective Catalytic Reduction (SCR) systems (A-4, A-6, and A-8), respectively. In

[3] NOx and CO emissions from the Peakers are abated by water injection & SCRs (A-4, A-6 and A-8) and oxidation catalysts (A-3, A-5, and A-7), which are downstream of the SCRs, respectively. In similar fashion, NOx and CO emissions from the combined cycle turbine (S-100), is reduced by steam injection and an oxidation catalyst (A-100), respectively.

similar fashion, NOx emissions from the combined cycle turbine (S-100), are controlled by steam injection. The NOx emissions from the afore-referenced turbines are continuously monitored through Continuous Emission Monitoring Systems (CEMS) to demonstrate compliance with the NOx limits outlined in NSPS GG, and federally enforceable permit conditions #2780 (part 11), #18102 (part 24.c) and #21961 (part IX.E). Also, NOx CEMS are also installed at auxiliary boilers S-101 and S-102 to continuously demonstrate compliance with the NOx limit outlined in NSPS Db, and federally enforceable permit conditions #2780 (part 11) and
#21961 (part IX.E). Therefore, the turbines and boilers are exempt from CAM for NOx per 40 CFR 64.2 (b)(1)(vi).

CO emissions from the "Peakers" (S-3, S-4, and S-5) are abated by oxidation catalysts (A-3, A-5, and A-7), which are downstream of SCRs (A-4, A-6, and A-8), respectively. Likewise, CO emissions from combined cycle turbine (S-100) are abated by oxidation catalyst (A-100). The CO emissions from the "Peakers" and the combined cycle turbine are continuously monitored through CO CEMS to demonstrate compliance with federally enforceable permit conditions #18102 (part 19.3) and #2780 (part 3.c.), respectively. Therefore, the turbines are exempt from CAM for CO per 40 CFR 64.2 (b)(1)(vi).

Risk Management Plan (RMP):

Selective Catalytic Reduction (SCR) systems A-4, A-6, and A-8 abate "Peakers" S-3, S-4 and S-5, respectively. At Calpine, the SCR process works by injecting a 19% aqueous ammonia solution into the turbine exhaust gas, in the presence of a catalyst. The ammonia reacts with the NOx emissions in the turbine exhaust gas to form nitrogen and water.

A health risk assessment performed by the District using air dispersion modeling under BAAQMD Application 2686, assuming a worst-case ammonia emission concentration of 10 ppmvd @ 15% O_2 due to ammonia slip from the SCRs, estimated an acute hazard index of 0.006 and a chronic hazard index of 0.0096. In accordance with the District's Toxic Risk Management Policy it was determined that the toxic impact of the ammonia slip was insignificant.

The storage and transport of ammonia used in the SCRs is subject to 40 CFR 68 "Chemical Accident Prevention Provisions", Subpart G "Risk Management Plan". 40 CFR 68, Subpart G and standard condition "I.K. Accidental Release" in the permit require facilities such as Calpine to maintain a RMP and implement a Risk Management Program to prevent accidental releases. The RMP provides information on the hazards of the substance handled at the facility and the programs in place to prevent and respond to accidental releases. Although ammonia is toxic if swallowed or inhaled and can irritate or burn the skin, eyes, nose, or throat, it is a commonly used material that is typically handled safely and without incident. The accident prevention and emergency response requirements reflect existing safety regulations and sound industry safety codes and standards.

Changes to 40 CFR 60, Subpart GG (NSPS GG):

The turbines at Calpine are subject to the NOx and SO2 limits in NSPS GG. Several sections in NSPS GG were amended and were later adopted into the Federal Register on July 8, 2004. The following discussion is limited to those sections that impact Calpine's permit.

Changes to Section 60.332 "Standards for nitrogen oxides":

- Terms to equations in paragraphs (a)(1) through (2) were revised;
- Paragraph (a)(3) was redesignated as paragraph (a)(4);
- Revised newly designated paragraph (a)(4);
- Added a new paragraph (a)(3)

In light of the above, terms to equations used in Section 60.332(a)(1), which will be discussed under the "NOx Discussion" in Section VII "Applicable Limits and Compliance Monitoring Requirements" of this document, will be revised. In addition, sections 60.332(a)(3) and (a)(4) will be added to Tables IV-A and IV-B in the permit.

Changes to Section 60.334 "Monitoring of Operations":

- Paragraphs (a) and (b) were revised;
- Paragraph (c) was redesignated as paragraph (j);
- Added a new paragraph (c);
- Added new paragraphs (d) through (i);
- Revised introductory text to newly redesignated paragraph (j), (j)(1) and (j)(2);
- Added a new paragraph (j)(5).

In light of the above, Sections 60.334(b), (h)(1), (h)(3), (i)(2), (j)(1)(iii), (j)(2)(i), (j)(2)(iii), and (j)(5) will be added to Tables IV-A and IV-B in the permit. The nitrogen and sulfur content monitoring frequency prescribed in Section 60.334(i)(2) has been added to Tables VII-A and VII-B. Lastly, Tables X B-1 and B-2 "Permit Shield – Subsumed Requirements" will be modified accordingly in light of the above changes.

The net effect of the above changes to NSPS GG will provide facilities such as Calpine operational flexibility with regards to monitoring. Specifically, the pre-July 2004 version of NSPS GG required Calpine to install and operate continuous monitoring systems to monitor and record the fuel consumption and the ratio of water to fuel fired in the "Peakers" (sources S-3 through S-5) which use water injection to control NOx emissions. In addition, Calpine also had to monitor and record the nitrogen content and sulfur content of the fuel fired in turbines S-3 through S-5, and S-100 on a daily basis.

The post-July 2004 version or the amended NSPS GG provides Calpine the flexibility of installing and monitoring emissions at turbines S-3 through S-5, and S-100 through CEMS consisting of NOx and O2 monitors instead of continuously monitoring and recording the fuel consumption and the ratio of water or steam to fuel being fired in the turbines. In addition, Calpine can avail of a provision to discontinue monitoring the nitrogen and sulfur content of the fuel fired in the afore-referenced turbines on a daily basis, if it can demonstrate through either purchase contracts, transportation contracts, or tariff sheets or by furnishing fuel sampling data that shows that the sulfur content of the gaseous fuel fired in the turbines is less than or equal to 20.0 grains/100 scf (~ 680 ppmv)[4].

[4] (20 gr S/100 scf x lb/7000 gr x lb-mol/16 lb S x 381 scf/lb-mol) = 680 ppmv

CEMS requirements outlined in the amended Section 60.334 will be incorporated into the permit, implying compliance with the NOx limit in NSPS GG will no longer be subsumed for the turbines at Calpine. It is likely that Calpine will discontinue monitoring the sulfur content of the fuel fired in the turbines on a daily basis, since part 23.b of permit condition 18102 limits the total sulfur content in the natural gas combusted in the turbines to 0.25 grains/100 scf (~ 8.5 ppmv)[5].

<u>Other changes</u>
The introduction to Section II will be modified to say that the SIP standards are now found on EPA's website and are not included as part of the permit.

V. Schedule of Compliance

A schedule of compliance is required in all Title V permits pursuant to BAAQMD Regulation 2-6-409.10 which provides that a major facility review permit shall contain the following information and provisions:

"409.10 A schedule of compliance containing the following elements:

- 10.1 A statement that the facility shall continue to comply with all applicable requirements with which it is currently in compliance;
- 10.2 A statement that the facility shall meet all applicable requirements on a timely basis as requirements become effective during the permit term; and
- 10.3 If the facility is out of compliance with an applicable requirement at the time of issuance, revision, or reopening, the schedule of compliance shall contain a plan by which the facility will achieve compliance. The plan shall contain deadlines for each item in the plan. The schedule of compliance shall also contain a requirement for submission of progress reports by the facility at least every six months. The progress reports shall contain the dates by which each item in the plan was achieved and an explanation of why any dates in the schedule of compliance were not or will not be met, and any preventive or corrective measures adopted."

Since the District has not determined that the facility is out of compliance with an applicable requirement, the schedule of compliance for this permit contains only sections 2-6-409.10.1 and 2-6-409.10.2.

<u>Changes to permit:</u>
A minor change will be made to this section to reflect the current standard text used by the District.

VI. Permit Conditions

During the Title V permit development, the District has reviewed the existing permit conditions, deleted the obsolete conditions, and, as appropriate, revised the conditions for clarity and enforceability. Each permit condition is identified with a unique numerical identifier, up to five digits.

When necessary to meet Title V requirements, additional monitoring, recordkeeping, or reporting will be added to the permit.

[5] (0.25 gr S/100 scf x lb/7000 gr x lb-mol/16 lb S x 381 scf/lb-mol) = 8.5 ppmv

All changes to existing permit conditions are clearly shown in "strike-out/underline" format in the proposed permit. When the permit is issued, all 'strike-out" language will be deleted; all "underline" language will be retained, subject to consideration of comments received.

The existing permit conditions are derived from previously issued District Authorities to Construct (A/C) or Permits to Operate (P/O). Permit conditions may also be imposed or revised as part of the annual review of the facility by the District pursuant to California Health and Safety Code (H&SC) § 42301(e), through a variance pursuant to H&SC § 42350 et seq., an order of abatement pursuant to H&SC § 42450 et seq., or as an administrative revision initiated by District staff. After issuance of the Title V permit, permit conditions will be revised using the procedures in Regulation 2, Rule 6, Major Facility Review.

The regulatory basis is listed following each condition. The regulatory basis may be a rule or regulation. The District is also using the following terms for regulatory basis:

- BACT: This term is used for a condition imposed by the Air Pollution Control Officer (APCO) to ensure compliance with the Best Available Control Technology in Regulation 2-2-301.
- Cumulative Increase: This term is used for a condition imposed by the APCO that limits a source's operation to the operation described in the permit application pursuant to BAAQMD Regulation 2-1-403.
- Offsets: This term is used for a condition imposed by the APCO to ensure compliance with the use of offsets for the permitting of a source or with the banking of emissions from a source pursuant to Regulation 2, Rules 2 and 4.
- PSD: This term is used for a condition imposed by the APCO to ensure compliance with a Prevention of Significant Deterioration permit issued pursuant to Regulation 2, Rule 2.
- TRMP: This term is used for a condition imposed by the APCO to ensure compliance with limits that arise from the District's Toxic Risk Management Policy.

Changes to permit:

Permit condition 18102 governs the operation of sources 3, 4, and 5 (turbines). Parts within the condition pertaining to and/or referencing the commissioning period will be deleted in the proposed permit since the commissioning period has elapsed. Specifically, parts 1 through 11 of the existing permit condition will be deleted in the proposed permit. In addition, parts 33 and 35 pertaining to emission offsets and requirements for submission of Title IV and Title V permits prior to first fire of the turbines, respectively, will be deleted in the proposed permit.

PSD permit conditions imposed on Calpine by the US EPA in 1985 before the construction of sources S-100, S-101 and S-102 will be listed under a new permit condition (# 21961) in the permit.

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.

The tables below contain only the limits for which there is no monitoring or 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.

These factors are the same as those historically applied by the District in developing monitoring for applicable requirements. It follows that, although Title V calls for a re-examination of all monitoring, there is a presumption that these factors will be appropriately balanced and incorporated in the District's prior rule development and/or permit issuance. It is possible that, where a rule or permit requirement has historically had no monitoring associated with it, no monitoring may still be appropriate in the Title V permit if, for instance, there is little likelihood of a violation. Compliance behavior and associated costs of compliance are determined in part by the frequency and nature of associated monitoring requirements. As a result, the District will generally revise the nature or frequency of monitoring only when it can support a conclusion that existing monitoring is inadequate.

The District has reviewed all monitoring and has determined the existing monitoring is adequate with the following exceptions.

NOX Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
SIMPLE CYCLE TURBINES: S-3, S-4, & S-5	NSPS GG 40 CFR 60.332 (a)(1)	99 ppmv @ 15% O2, dry	CEMS
COMBINED CYCLE TURBINE: S-100	NSPS GG 40 CFR 60.332 (a)(1)	82 ppmv @ 15% O2, dry	CEMS
AUXILIARY BOILERS: S-101 & S-102	NSPS Db 40 CFR 60.b(a)(1)(ii)	0.2 lb/MM Btu	CEMS

NOx Discussion:

Turbines:

Section 60.332(a)(1) in 40 CFR 60, Subpart GG prescribes the following equation to compute the permissible NOx emissions levels from simple cycle stationary gas turbines, such as sources S-3 through S-5:

$$STD = 0.0075\frac{(14.4)}{Y} + F$$

Where:

STD = allowable ISO corrected (if required as given in § 60.335(b)(1)) NOx emission concentration (percent by volume at 15 percent oxygen and on a dry basis),

Y = manufacturer's rated heat rate at manufacturer's rated load (kilojoules per watt hour) or, actual measured heat rate based on lower heating value of fuel as measured at actual peak load for the facility. The value of Y shall not exceed 14.4 kilojoules per watt hour, and

F = NOx emission allowance for fuel-bound nitrogen as defined in paragraph (a)(4) of this section.

As an example, consider S-3. The maximum heat input rate for S-3 is 467.6 MMBTU/hr. In order to find “STD” we need to convert the maximum heat input rate from “MMBTU/hr” to “kJ/watt-hr” to determine the value of “Y”.
This can be accomplished as follows:
= (467.6 MMBTU/hr) x (10E6 BTU/MMBTU) x (1054.2 J/BTU) x (kJ/1000J) x (1/45 MW) x (1 MW/10E6 watts)
= 10.95 kJ/watt-hr

Since S-3 exclusively combusts natural gas, it can be assumed that the percent weight of fuel-bound nitrogen in natural gas is < 0.015%. Per guidance in paragraph (a)(4) of Section 60.332, the value of “F” is equal to zero when the percent weight of fuel-bound nitrogen is < 0.015%.

Substituting the values of “Y” and “F” in the above equation, STD = 99 ppmvd @ 15% O2.

In similar fashion, consider the combined cycle stationary gas turbine S-100. The maximum heat input for S-100 is 1,085 MMBTU/hr. In order to find "STD" the maximum heat input rate in "MMBTU/hr" is converted to "kJ/watt-hr" to determine the value of "Y".
This is accomplished as follows:
= (1085 MMBTU/hr) x (10E6 BTU/MMBTU) x (1054.2 J/BTU) x (kJ/1000J) x (1/87 MW) x (1 MW/10E6 watts)
= 13.15 kJ/watt-hr

Since S-100 exclusively combusts natural gas, it is assumed that the percent weight of fuel-bound nitrogen in natural gas is < 0.015%. Per guidance in paragraph (a)(4) of Section 60.332, the value of "F" is equal to zero when the percent weight of fuel-bound nitrogen is < 0.015%.

Substituting the values of "Y" and "F" in the above equation, STD = 82 ppmvd @ 15% O2.

It can be seen from the above discussion, that in order for sources S-3 through S-5 and S-100 to be in compliance with 40 CFR 60, Subpart GG, the NOx emissions from each individual simple cycle turbine (S-3, S-4, or S-5) and from the combined cycle turbine (S-100) must be below 99 ppmvd @ 15% O2 and 82 ppmvd @ 15% O2, respectively.

As previously discussed in the "Background" section under "Title V Permitting History", Gilroy Energy Center LLC submitted Application 2686 in April 2001 to obtain permits for sources S-3 through S-5. The afore-referenced sources were subject to the District's prevailing BACT requirements (Document #: 89.1.2, dated August 28, 2000) for simple cycle turbines rated at less than 50 MW. To meet the District's BACT1 "Technologically Feasible/Cost-Effective" level of control, Gilroy Energy Center LLC installed SCRs - A-4 (at S-3), A-6 (at S-4) and A-8 (at S-5), with ammonia injection in conjunction with combustion modifications and water injection to limit NOx emissions from sources S-3 through S-5 to under 5 ppmvd @ 15% O2 per turbine. The NOx emissions from the above sources are continually monitored by Continuous Emission Monitoring Systems (CEMS). The requirement to limit the NOx emissions from each turbine to below 5 ppmvd @ 15% O2 and the requirement to continually monitor NOx emissions by CEMS manifest themselves as "part 19.1" under permit condition 18102 in the proposed permit. It can be concluded that sources S-3 through S-5 would most definitely comply with the less stringent NOx limit (~ 99 ppmvd @ 15% O2) prescribed in 40 CFR 60, Subpart GG if NOx emissions from the turbines are below 5 ppmvd @ 15% O2 (1-hour rolling average) as outlined in part 19.1 of permit condition 18102.

In similar fashion, part 1.e. of permit condition 2780 and part IX.C of Calpine's PSD permit limit NOx emissions from S-100 to 21 ppmvd @ 15% O2 and 25 ppmvd @ 15% O2 (over a 3-hour average), respectively. Part 11 of permit condition 2780 and part IX.E of Calpine's PSD permit contain explicit requirements to continuously monitor NOx emissions through CEMS at S-100. It can be concluded that S-100 would most definitely comply with the less stringent NOx limit
(~ 82 ppmvd @ 15% O2) prescribed in 40 CFR 60, Subpart GG if NOx emissions from the turbine is below 25 ppmvd @ 15% O2 (3-hour rolling average) as outlined in parts 1.a and IX.C of permit conditions 2780 and 21961, respectively.

Auxiliary Boilers:

Part 4 in permit condition 2780 and part IX.C. in permit condition 14299 limit the individual NOx emissions from sources S-101 and S-102 to 40 ppmvd @ 3% O2 averaged over any three-hour period. The above NOx concentration limit (in ppmvd) is converted to a NOx emission limit based on the heat input (lb/MMBTU) as follows:

= (40 ppmvd) (20.95 – 0)/(20.95 – 3) = 46.69 ppmv NOx @ 0% O2
= (46.69/10E6) (1 lbmol/385.3 dscf) (46.01 lb NO2/lbmol) (8535 dscf/MMBTU)
= 0.0475 lb NO2/MMBTU

Part 11 of permit condition 2780 requires Calpine Gilroy Cogen, L.P to continually monitor NOx emissions by CEMS at S-101 and S-102 in the proposed permit.

Therefore, it can be concluded that monitoring to demonstrate compliance with the less stringent NOx limit (~ 0.2 lb NO2/MMBTU) prescribed in 40 CFR 60, Subpart Db is subsumed by the CEMS monitoring discussed above.

POC Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
COMBINED CYCLE TURBINE AND AUXILIARY BOILERS: S-100, S-101 & S-102	BAAQMD Permit Condition 2780 part 6	< 40 TPY NMHC for S-100, S-101, S-102	None

POC Discussion:

As previously discussed in the “Facility Description” section, sources 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)[6].

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.

As previously discussed in the “Background” section under “Title V Permitting History”, Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C have indicated that the turbine and boilers at Calpine Gilroy Cogen, L.P. will exclusively combust natural gas. Therefore, 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 warranted.

CO Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
AUXILIARY BOILERS: S-101 & S-102	BAAQMD Regulation 9-7-301.2	400 ppmv @ 3%O2, dry, 3-hr average, Gaseous Fuel	None

CO Discussion:

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 9-7-301.2 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)

[6] Heating value of 1020 BTU/scf

= 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.

SO2 Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
SIMPLE CYCLE TURBINES: S-3, S-4, & S-5	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
	NSPS GG 40 CFR 60.333(a)	0.015% (vol.) @15% O_2 (dry)	None
COMBINED CYCLE TURBINE: S-100	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
	BAAQMD Regulation 9-1-302	300 ppm (dry)	None
	NSPS GG 40 CFR 60.333(a)	0.015% (vol.) @15% O_2 (dry)	None
AUXILIARY BOILERS: S-101 & S-102	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
	BAAQMD Regulation 9-1-302	300 ppm (dry)	None
~~**COMBINED CYCLE TURBINE AND AUXILIARY BOILERS:** S-100, S-101 & S-102~~	~~BAAQMD Permit Condition 2780 part 10.a~~	~~< 43.46 lb/day for S-100, S-101, and S-102~~	~~None~~
EMERGENCY STANDBY FIRE PUMP POWERED BY DIESEL ENGINE: S-6	BAAQMD 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
	BAAQMD 9-1-304	Sulfur Content in Liquid Fuel < 0.5% by weight	Fuel Oil Vendor Certification

SO2 Discussion:

Compliance with Regulation 9-1-301:

(For sources S-3 through S-5, and S-100 through S-102)

The maximum individual heat input rates of sources S-3 through S-5 and S-100 are 467.6 MMBTU/hr, and 1,085 MMBTU/hr, respectively. The SO_2 emission rate in US EPA AP-42, Table 3.1-2a "Emission Factors for Criteria Pollutants and Greenhouse Gases From Stationary Gas Turbines", April 2000, is 0.94*S lb/MMBTU, where "S" is the percent sulfur in the fuel. US EPA AP-42 guidance recommends an emission factor of 3.4E-3 lb/MMBTU, when "S" is not available.

It is Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C's contention that the concentration of sulfur in the fuel combusted in the turbines is 0.25 grains/100 scf. If we conservatively assume a sulfur concentration of 1 grain/100 scf, we can derive a sulfur emission factor based on the fuel input as follows:
= (1 gr/100 scf) x (scf/1020 BTU) x (10E6 BTU/MMBTU) x (1 lb/7000 gr) x (64 lbs SO2/32 lbs S)
= 2.8E-3 lb/MMBTU

The hourly SO2 emission rates from sources S-3 through S-5 and S-100, using the above emission factor, is equal to 1.31 lbs/hr per simple cycle turbine and 3.04 lbs/hr for the combined cycle turbine. In similar fashion, the hourly SO2 emission rate from the auxiliary boilers S-101 and S-102, using the above emission factor is equal to 0.29 lbs/hr per auxiliary boiler. The worst-case SO2 emissions, assuming the four turbines and two auxiliary boilers operate for 8,760 hrs/yr, is equal to 33 TPY[7].

(For source S-6)

The diesel engine that powers the fire pump S-6 at Calpine is a Loss of Exemption I.C. Engine. In other words, the engine was previously exempt from permitting but was later required to obtain a Permit to Operate due to changes in the District's regulations. Emission factors used to estimate criteria pollutant emissions from S-6 was taken from US EPA AP-42, Table 3.3-1 "Emission Factors For Uncontrolled Gasoline and Diesel Industrial Engines", October 1996. The emission factor for SO2 furnished in the above referenced table is 0.00205 lb/hp-hr. The PTE calculation using EPA's guidance memorandum entitled "Calculating Potential to Emit (PTE) for Emergency Generators" dated September 6, 1995 assumes that fire pump's such as S-6 are unlikely to run, even in a worst case scenario, for more than 500 hours per source per year. Therefore, the potential to emit calculation are based on 500 hours per year of fire pump operation. Source S-6 is rated at 170 hp.

Therefore, S-6's SO2 PTE is estimated as follows:
= (500 hr/yr) x (170 hp) x (0.00205 lb SO2/hp-hr) x (1 ton SO2/2000 lb S02) = 0.09 ton/yr

In conclusion, area monitoring to demonstrate compliance with the ground level SO2 concentration requirements of Regulation 9-1-301 is at the discretion of the APCO (per BAAQMD Regulation 9-1-501). As discussed in the preceding paragraphs, Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C does not have equipment that emit large quantities of SO2 emissions and therefore the company is not required to have ground level monitoring by the APCO. Moreover, the potential emissions of SO2 are not concentrated in one point source, but rather in a number of small sources within the plant. For comparison, the

[7] (1.31 lbs/hr/simple cycle turbine x 3 simple cycle turbines) + 3.04 lbs/hr/combined cycle turbine + (0.29 lbs/hr/auxiliary boiler x 2 auxiliary boilers) = 7.55 lbs/hr x 8760 hrs/yr x 1 ton/2000 lbs = 33 TPY.

refineries in the Bay Area have SO_2 emissions ranging from 760 TPY to 6900 TPY versus a sum total of 33 TPY from the turbines, boilers, and fire pump at Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C. Refineries in the Bay Area have ground level monitors; yet they rarely exceed the Regulation 9-1-301 limits. Therefore, no periodic monitoring has been added to assure compliance with Regulation 9-1-301 for sources at Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C.

Compliance with Regulation 9-1-302:

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 such as S-3 through S-5, S-100, S-101, and S-102, do not need additional monitoring to verify compliance with Regulation 9, Rule 1, since the sulfur content of natural gas is very low. Therefore, no monitoring is necessary at the above sources to demonstrate compliance with the 300 ppm SO_2 limit in Regulation 9-1-302.

Compliance with Regulation 9-1-304:

As previously discussed in the preceding discussion under “Regulation 9-1-301”, the diesel engine that powers the fire pump at Calpine is Loss of Exemption I.C. Engine i.e. a source that was previously exempt from permitting but was later required to obtain a Permit to Operate due to changes in the District’s regulations. As a result there are no permit conditions governing the operation of S-6. However, “Table VII-E” in the permit explicitly requires Calpine to obtain certifications of the sulfur content in the fuel from the fuel oil vendor to demonstrate compliance with Regulation 9-1-304, which limits the sulfur content in the fuel to 0.5% by weight. This type of compliance is a standard monitoring practice to demonstrate compliance with Regulation 9-1-304.

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 <u>or</u>
- Combust fuel with sulfur content less than or equal to 0.8% by weight (8000 ppmw).

As previously discussed under the “Compliance with Regulation 9-1-301” in the preceding paragraphs in this section, the sulfur concentration of the PUC quality natural gas combusted in the turbines is unlikely to exceed 0.25 grains/100 scf. By conservatively assuming a sulfur concentration of 1 grain/100 scf, we can compare the resulting SO_2 concentration to the afore-referenced conditions in Section 60.333(a) as follows:

Convert the sulfur emission factor i.e. 2.8E-3 lb/MMBTU, previously derived in the preceding “Compliance with Regulation 9-1-301” paragraph to obtain an SO_2 emission concentration as follows:
= (2.83E-3 lb/MMBTU) x (385.3 dscf/1 lbmol) x (1 lb-mol/64.06 lb SO2) (MMBTU/8535 dscf)
= 2 ppmvd SO2 0% O2

The above concentration is equivalent to:
(2 ppmvd) (20.95-15/20.95-0) = 0.6 ppmv SO2, dry @ 15% O2

It can be seen from the above calculations that the fuel combusted at the stationary turbines at Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C complies with both the conditions outlined in NSPS GG. In addition, permit conditions 14299 (part 1) and 18102 (part 23.b.) that govern the operation of S-100 and S-3 through S-5, respectively, require only PUC quality natural gas to be combusted at the above sources. Therefore, no monitoring is necessary at the above sources to demonstrate compliance with Section 60.333(a) in NSPS GG.

PM Sources

S# & Description	Emission Limit Citation	Federally Enforceable Emission Limit	Monitoring
SIMPLE CYCLE TURBINES: S-3, S-4, & S-5	BAAQMD Regulation 6-301	> Ringelmann No. 1 for no more than 3 minutes in any hour	None
	BAAQMD condition #18102, part 6	> Ringelmann No. 1 for no more than 3 minutes in any hour or equivalent 20% opacity	None
	BAAQMD Regulation 6-310	0.15 gr/dscf	None
COMBINED CYCLE TURBINE: S-100	BAAQMD Regulation 6-301	> Ringelmann No. 1 for no more than 3 minutes in any hour	None
	BAAQMD Regulation 6-310	0.15 gr/dscf	None
AUXILIARY BOILERS: S-101 & S-102	BAAQMD Regulation 6-301	> Ringelmann No. 1 for no more than 3 minutes in any hour	None
	BAAQMD Regulation 6-310.3	0.15 grain/dscf @ 6% O2	None
COMBINED CYCLE TURBINE AND AUXILIARY BOILERS: S-100, S-101 & S-102	BAAQMD Permit Condition 2780 part 6	< 25 TPY total FP for S-100, S-101, S-102	None
COOLING TOWER: S-104	BAAQMD Regulation 6-301	Ringelmann 1.0	None
	BAAQMD Regulation 6-310	0.15 gr/dscf	None
	BAAQMD Regulation 6-311	$4.10P^{0.67}$ lb/hr, where P is process weight, ton/hr	None
EMERGENCY STANDBY FIRE PUMP POWERED BY DIESEL ENGINE: S-6	BAAQMD Regulation 6-303	Ringelmann 2.0 For less than 3 minutes in an hour	None
	BAAQMD Regulation 6-310	0.15 gr/dscf	None

PM Discussion:

Compliance with Regulation 6-301:

(For sources S-3 through S-5, and S-100 through S-102)

BAAQMD Regulation 6-301 limits visible emissions to no darker than 1.0 on the Ringelmann Chart (except for periods or aggregate periods less than 3 minutes in any hour). Visible emissions are normally not associated with combustion of gaseous fuels, such as natural gas. Sources S-3 through S-5, and S-100 through S-102, exclusively combust natural gas. 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 assure compliance with Regulation 6-301 for the above sources.

In similar fashion, no additional monitoring is required to demonstrate compliance with part 18 of permit condition 18102 that governs the operation of sources S-3 through S-5.

Compliance with Regulation 6-303:

(For source S-6)

Source 6 is subject to the Ringelmann 2.0 limit, which is equivalent to 40% opacity, and is a very high limit. Since the diesel engine that powers the fire pump will only operate during emergencies, coupled with the fact that it is highly unlikely that emissions from the engine will exceed the Ringelmann 2.0 limit, no periodic monitoring for visible emissions is recommended for S-6.

Compliance with Regulation 6-310:

(For sources S-3 through S-5, and S-100 through S-102)

BAAQMD Regulation 6-310 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 through S-5, and S-100 through S-102, exclusively combust natural gas. 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 assure compliance with this limit for the above sources.

(For source S-6)

The diesel engine that powers the fire pump S-6 is rated at 170 hp. Emission factors used to estimate criteria pollutant emissions from S-6, were taken from US EPA AP-42, Table 3.3-1 “Emission Factors For Uncontrolled Gasoline and Diesel Industrial Engines”, October 1996. An emission factor of 0.0022 lb/hp-hr for PM10 is applicable to source S-6, since it is rated at less than 600 hp.

Regulation 6-310 limits Filterable PM (PM) emissions to 0.15 gr/dscf. In order to compare the standard emission rate prescribed in AP-42 to the Regulation 6-310 limit, we need to convert both emission rates to an emission rate with the same metric (lb/MM BTU).

We convert Regulation 6-310 as follows:

The F_d-Factor for PM furnished in 40 CFR Part 60, Appendix A, Method 19 for Crude, Residual, or Residual Oil is 9,190 dscf/MM BTU. Please note that an “F” factor is the ratio of the gas volume of the products of combustion to the heat content of the fuel.
Therefore, the emission rate “E”
= (9190 dscf/MMBTU * 0.15 gr/dscf) / (7000 gr/lb)
= 0.1969 lb/MMBTU
The AP-42 emission factor (in lbs/hp-hr) for S-6 is converted to lbs/MMBTU as follows[8]:
[(0.0022 lb/hp-hr * 170 hp) / (20 gal/hr * 141000 BTU/gal)] * (10^6 BTU/MMBTU)
= 0.13 lb/MMBTU

Since, the AP-42 emission rate is well below the Regulation 6-310 limit, it is concluded that periodic PM monitoring for the fire pump is not necessary.

Compliance with Part 6 of BAAQMD Permit Condition 2780:

(For sources S-100 through S-102)

As previously discussed in the “Facility Description” section under the Calpine Gilroy Cogen, L.P discussion and the under the PSD discussion in the “Complex Applicability Determination” section, sources 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[9] and 12 TPY[10], 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.

Calpine Gilroy Cogen, L.P & Calpine Gilroy Energy Center, L.L.C has indicated to the District that all the above sources will exclusively combust PUC quality natural gas and that fuel oil will never be 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.

Compliance with Regulation 6 standards:

(For S-104)

As previously discussed in the preceding paragraphs, BAAQMD Regulation 6-301 limits visible emissions to no darker than 1.0 on the Ringelmann Chart (except for periods or aggregate periods less than 3 minutes in any hour). Particulate emissions from cooling towers come from

[8] Assuming a average worst-case fuel consumption rate of 20 gallons/hr for the fire pump.
[9] (180 x 3250/14 x 2000) + (32 x 1975/14 x 2000) = 23 TPY
[10] (60 x 5335/14 x 2000) + (13 x 1975/14 x 2000) = 12 TPY

dissolved solids in the cooling tower water and are therefore expected to be fairly constant and not subject to operational control.

BAAQMD Regulation 6-310 limits filterable particulate (FP) emissions from any source to 0.15 grains per dry standard cubic foot (gr/dscf) of exhaust volume. The worst-case grain loading from S-104 is calculated, per information provided in the cooling tower vendor data sheet, as follows:

Cooling water circulation rate	24,000 gpm
Drift rate	0.002%
Maximum total dissolved solids	3,000 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. PM10 emission rate = (240 lb/hr)(3,000 ppm)/10^6
= 0.72 lb/hr

Grain loading = (0.72 lb/hr)(hr/60 min)(7000 gr/lb)/(540,500 dscfm)
= 0.00015 gr/dscf

It can be seen from above, that the worst-case grain loading rate from S-104 is much less than Regulation 6-310 limit. Since the grain loading is so low, the cooling tower is not expected to have visible emissions. In addition, a search in the District's database revealed that Calpine Gilroy Cogen, L.P and Calpine Gilroy Energy Center, L.L.C has received no violations or complaints in regard to particulate emissions. The District therefore is satisfied that additional periodic monitoring requirements to assure compliance with Regulations 6-301 and 6-310 for S-104 are not necessary.

BAAQMD Regulation 6-311 limits the emission rate of general particulate operations by the following equation:
$E = 0.026 * P^{0.67}$;
Where, E is the Actual Emission Rate (in lb/hr) and P is the Actual Process Rate (in lbs/hr). From Table 1 under Regulation 6-311 it can be seen that the value of "E" when "P" is equal to 550 lbs/hr is 1.8 lbs/hr.

The maximum PM10 emission rate derived in the preceding paragraphs i.e. 0.72 lbs/hr, is below the "E" value discussed above. Therefore, it is concluded that periodic monitoring to demonstrate compliance with the Regulation 6-311 is not necessary for S-104.

<u>Other changes to permit</u>
A note has been added at the beginning of the section to clarify that this section is a summary of the limits and monitoring, and that in the case of a conflict between Sections I-VI and Section VII, the preceding sections take precedence.

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.

IX. Permit Shield:

The District rules allow two types of permit shields. The permit shield types are defined as follows: (1) A provision in a major facility review permit explaining that specific federally enforceable regulations and standards do not apply to a source or group of sources, or (2) A provision in a major facility review permit explaining that specific federally enforceable applicable requirements for monitoring, recordkeeping and/or reporting are subsumed because other applicable requirements for monitoring, recordkeeping, and reporting in the permit will assure compliance with all emission limits.

The second type of permit shield is allowed by EPA's White Paper 2 for Improved Implementation of the Part 70 Operating Permits Program. The District uses the second type of permit shield for all streamlining of monitoring, recordkeeping, and reporting requirements in Title V permits. The District's program does not allow other types of streamlining in Title V permits.

Changes to permit

Calpine Gilroy Cogen, L.P and Calpine Gilroy Energy Center, L.L.C currently has one permit shield of the first type (Non-Applicable Requirements) and one permit shield of the second type (Subsumed Requirements). Please note that Tables X-B-1 and X-B-2, pertaining to the second type of permit shields (Subsumed Requirements) were deleted in light of the July 2004 amendments to NSPS GG that was previously discussed under the "Complex Applicability Discussion" in "Section IV. Source-Specific Applicable Requirements". In light of the above changes, Table X-B-3 will be renumbered to Table X-B-1.

Table X-B-1:

Compliance with 60.334(a), 60.334(b)(2) that was amended to 60.334(h)(1), and 60.334(c)(1) that was amended to 60.334(j)(iii), were previously subsumed by compliance with part 24 of permit condition 18102. In light of the July 2004 amendments to NSPS GG, the afore-referenced requirements will no longer be subsumed and will be deleted from Table X-B-1 for the following reasons:

- The pre-July 2004 version of NSPS GG required Calpine to install and operate continuous monitoring systems to monitor and record the fuel consumption and the ratio of water to fuel fired in the "Peakers" (sources S-3 through S-5) which use water injection to control NOx emissions to meet the requirements in 60.334(a). In addition, the pre-July 2004 version of NSPS GG would have required Calpine to monitor and record the nitrogen content and sulfur content of the fuel fired in turbines S-3 through S-5 on a daily basis to meet the requirements in 60.334(b)(2).

The post-July 2004 version of NSPS GG provides Calpine the flexibility of installing and monitoring emissions at turbines S-3 through S-5 through CEMS consisting of NOx and O2 monitors instead of continuously monitoring and recording the fuel consumption and the ratio of water to fuel being fired in the turbines.

- Per the amended NSPS GG, Calpine can avail of a provision, under either 60.334(h)(3)(i) <u>or</u> 60.334(h)(3)(ii), to discontinue monitoring the nitrogen and sulfur content of the fuel fired in the afore-referenced turbines on a daily basis, if it can demonstrate through either purchase contracts, transportation contracts, or tariff sheets <u>or</u> by furnishing fuel sampling data that shows that the sulfur content of the gaseous fuel fired in the turbines is less than or equal to 20.0 grains/100 scf (~ 680 ppmv). Therefore, compliance with 60.334(h)(1) will no longer be subsumed through compliance with part 23.b of permit condition 21961.

- The averaging time to demonstrate compliance with the NOx limit in part 19.1 of permit condition 18102 is a 1-hour rolling average. In contrast, the averaging time for excess NOx emissions under the amended 60.334(j)(iii) is a 4-hour rolling average. Therefore, compliance with 60.334(j)(iii) will no longer be subsumed through compliance with parts 19.1 and 24 of permit condition 18102.

<u>Table X-B-2:</u>

Compliance with 60.334(a) and 60.334(c)(1) {that was amended to 60.334(j)(iii)} were previously subsumed by compliance with part IX.E of permit condition 21961. In similar fashion, compliance with 60.334(b)(2) {that was amended to 60.334(h)(1)} and 60.334(c)(2) {that was amended to 60.334(j)(2)(i)} were subsumed by compliance with part 1 of permit condition 14299. In light of the July 2004 amendments to NSPS GG the afore-referenced requirements will no longer be subsumed and will be deleted from Table X-B-2 for the following reasons:

- Section 60.334(a) in the pre-July 2004 version of NSPS GG required an owner/operator of a turbine that used water injection to control NOx emissions to install and operate continuous monitoring systems to monitor and record the fuel consumption and the ratio of water to fuel fired in the turbine. The combined cycle turbine S-100 uses steam injection to control NOx emissions. Therefore, S-100 should never will be subject to 60.334(a) and/or included in Table X-B-2, in the first place.

- A 3-hour averaging time is used to demonstrate compliance with the NOx limit in part IX.E.3.e of permit condition 21961. In contrast, the averaging time for excess NOx emissions under the amended 60.334(j)(iii) is a 4-hour rolling average. Therefore, compliance with 60.334(j)(iii) will no longer be subsumed through compliance with IX.E.3.e of permit condition 21961.

- The pre-July 2004 version of NSPS GG required Calpine to monitor and record the nitrogen content and sulfur content of the fuel fired in S-100 on a daily basis to meet the requirements in 60.334(b)(2). Per the amended NSPS GG, Calpine can avail of a provision, under either 60.334(h)(3)(i) <u>or</u> 60.334(h)(3)(ii), to discontinue monitoring the nitrogen and sulfur content of the fuel fired at the afore-referenced turbine on a daily basis, if it can demonstrate through either purchase contracts, transportation contracts, or tariff sheets or by furnishing fuel sampling data that shows that the sulfur content of the gaseous fuel fired in S-100 is less than or equal to 20.0 grains/100 scf (~ 680 ppmv). Therefore, compliance with 60.334(h)(1) will no longer be subsumed through compliance with part 1 of permit condition 14299.

- The averaging time to demonstrate compliance with the NOx limit in part 19.1 of permit condition 18102 is a 1-hour rolling average. In contrast, the averaging time for excess NOx emissions under the amended 60.334(j)(iii) is a 4-hour rolling average. Therefore, compliance with 60.334(j)(iii) will no longer be subsumed through compliance with parts 19.1 and 24 of permit condition 18102.

- Compliance with the pre-July 2004 version of 60.334(c)(2) was previously subsumed through compliance with part 1 of permit condition 14299. As previously discussed, the July 2004 amendments to NSPS GG would allow Calpine, under either 60.334(h)(3)(i) or 60.334(h)(3)(ii), to discontinue monitoring the nitrogen and sulfur content of the fuel fired at the afore-referenced turbine on a daily basis, if it can demonstrate through either purchase contracts, transportation contracts, or tariff sheets or by furnishing fuel sampling data that shows that the sulfur content of the gaseous fuel fired in S-100 is less than or equal to 20.0 grains/100 scf (~ 680 ppmv). Therefore, compliance with 60.334(j)(2)(i) will no longer be subsumed through compliance with part 1 of permit condition 14299.

Lastly, please note that requirements for sections 60.46b, 60.48b, and 60.49b under NSPS Db as it relates to auxiliary boilers S-101 and S-102 will be subsumed, if Calpine demonstrates compliance with parts 11 and 14 of permit condition 2780 due to the fact that the NOx limit for the boilers in part 4 of permit condition 2780 does not explicitly exclude boiler startups and shutdowns from the 3-hour averaging period. Therefore, it is safe to subsume the afore-referenced NSPS Db requirements.

D. Alternate Operating Scenarios

No alternate operating scenario has been requested for this facility.

E. Compliance Status

A June 14, 2005 office memorandum from the Director of Compliance and Enforcement, to the Director of Permit Services, presents a review of the compliance record of Gilroy Energy Center (Site #: B1180). The Compliance and Enforcement Division staff has reviewed the records for Gilroy Energy Center's for the period from June 1, 2000 through May 31, 2005. This review was initiated as part of the District evaluation of an application by Gilroy Energy Center for a Title V permit renewal. During the period subject to review, activities known to the District include:

- There were no Notices of Violation issued for the period of May 31, 2004 to May 31, 2005.
- The District did not receive any air pollution complaints alleging Gilroy Energy Center as the source for the period of June 1, 2000 to May 31, 2005.
- The District received two notifications for continuous emission monitoring (CEM) indicated excesses for Nitrogen Oxide and Carbon Monoxide for the period of May 31, 2004 to May

31, 2005. Both excesses are currently being evaluated and the sources associated with the monitors are currently in compliance. No equipment breakdowns were reported or documented by District Staff.
- The District reviewed Gilroy Energy Center's Annual Compliance Certifications for 2000-2005 and found no on-going non-compliance.
- There are no enforcement agreements, open variances, or open abatement orders for Gilroy Energy Center.

F. Differences between the Application and the Proposed Permit

The renewal Title V permit application was submitted on December 2, 2002. This version is the basis for constructing the proposed Title V permit. There are no significant differences between the renewal Title V application and the proposed permit.

H:\Engineering\TITLE V Permit Appls\1 ALL T5 Application Files here\B1180\Renew - 6748\1.0 Working docs\B1180-SOBa.doc

APPENDIX A

BAAQMD COMPLIANCE REPORT

COMPLIANCE AND ENFORCEMENT DIVISION

OFFICE MEMORANDUM

June 14, 2005

TO: BRIAN BATEMAN, DIRECTOR, ENGINEERING DIVISION

FROM: KELLY WEE, DIRECTOR OF ENFORCEMENT for

SUBJECT: REVIEW OF COMPLIANCE RECORD OF:

GILROY ENERGY CENTER (SITE #B1180)

Background

This review was initiated as part of the District evaluation of an application by Gilroy Energy Center 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 to Operate. The purpose of this review is to assure that any non-compliance problems identified during the prior term or twelve months have been adequately addressed, or are properly incorporated into a Title V permit compliance schedule. Additionally, the review is intended to recommend, if necessary, any additional permit conditions and limitations to improve compliance.

Finding

The Enforcement Division staff has commenced a review of the records for Gilroy Energy Center for the period of June 1, 2000 to May 31, 2005. During this review period Gilroy Energy Center's activities known to the District include:

> The District did not issue any Notices of Violation for the period of May 31, 2004 to May 31, 2005.
>
> The District did not receive any air pollution complaints alleging Gilroy Energy Center as the source for the period of June 1, 2000 to May 31, 2005.
>
> The District received two notifications for continuous emission monitoring (CEM) indicated excesses for Nitrogen Oxide and Carbon Monoxide for the period of May 31, 2004 to May 31, 2005. Both excesses are currently being evaluated and the sources associated with the monitors are

currently in compliance. No equipment breakdowns were reported or documented by District Staff.

Staff reviewed Gilroy Energy Center's Annual Compliance Certifications for 2000-2005 and found no on-going non-compliance.

There are no enforcement agreements, open variances, or open abatement orders for Gilroy Energy Center.

Conclusion

The Compliance and Enforcement Division has made a determination that for the period of June 1, 2000 to May 31, 2005 Gilroy Energy Center (#B1180) was in continuous compliance or intermittent compliance, all sources have returned to compliance by the end of the period, facility is currently in compliance, there is no evidence of on-going non-compliance and no Title V permit compliance schedule is necessary.

KW:JB:TG:jk

CC: Brenda Cabral
Tony Gambardella
Steve Chin

APPENDIX B

GLOSSARY

ACT
Federal Clean Air Act

APCO
Air Pollution Control Officer

API
American Petroleum Institute

ARB
Air Resources Board

BAAQMD
Bay Area Air Quality Management District

BACT
Best Available Control Technology

BARCT
Best Available Retrofit Control Technology

C5
An Organic chemical compound with five carbon atoms

C6
An Organic chemical compound with six carbon atoms

CAA
The federal Clean Air Act

CAAQS
California Ambient Air Quality Standards

CAPCOA
California Air Pollution Control Officers Association

CEC
California Energy Commission

CEQA
California Environmental Quality Act

CEM
A "continuous emission monitor" is a monitoring device that provides a continuous direct measurement of some pollutant (e.g. NOx concentration) in an exhaust stream.

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

CO2
Carbon Dioxide

Cumulative Increase
The sum of permitted emissions from each new or modified source since a specified date. Used to determine whether threshold-based requirements are triggered.

District
The Bay Area Air Quality Management District

dscf
Dry Standard Cubic Feet

dscm
Dry Standard Cubic Meter

E 6, E 9, E 12
Very large or very small number values are commonly expressed in a form called scientific notation, which consists of a decimal part multiplied by 10 raised to some power. For example, 4.53 E 6 equals (4.53) x (10^6) = (4.53) x (10 x 10 x 10 x 10 x 10 x 10) = 4,530,000. Scientific notation is used to express large or small numbers without writing out long strings of zeros.

EGT
Exhaust Gas Temperature

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 (HAP), and Part 72 (Permits Regulation, Acid Rain), and also 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.

FR
Federal Register

GDF
Gasoline Dispensing Facility

GLC
Ground level concentration.

GLM
Ground Level Monitor

grains
1/7000 of a pound

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 both 40 CFR Part 63, and District Regulation 2, Rule 5.

H2S
Hydrogen Sulfide

HHV
Higher Heating Value. The quantity of heat evolved as determined by a calorimeter where the combustion products are cooled to 60F and all water vapor is condensed to liquid.

LHV
Lower Heating Value. Similar to the higher heating value (see HHV) except that the water produced by the combustion is not condensed but retained as vapor at 60F.

Major Facility
A facility with potential emissions of regulated air pollutants greater than 100 tons per year, greater than or equal to 10 tons per year of any single hazardous air pollutant, and/or greater than or equal to 25 tons per year of any combination of hazardous air pollutants, or such lesser quantity 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 Act and implemented by District Regulation 2, Rule 6.

MOP
The District's Manual of Procedures.

MSDS
Material Safety Data Sheet

MW
Megawatts

NA
Not Applicable

NAAQS
National Ambient Air Quality Standards

NESHAPS
National Emission Standards for Hazardous Air Pollutants. Contained in 40 CFR Part 61.

NMHC
Non-methane Hydrocarbons

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 Act, and implemented by both 40 CFR Part 60 and District Regulation 10.

NSR
New Source Review. A federal program for preconstruction review and permitting of new and modified sources of air pollutants for which the District is classified "non-attainment". Mandated by Title I of the Clean Air Act and implemented by 40 CFR Parts 51 and 52 as well as District Regulation 2, Rule 2. (Note: There are additional NSR requirements mandated by the California Clean Air Act.)

O2
The chemical name for naturally-occurring oxygen gas.

Offset Requirement
A New Source Review requirement to provide federally enforceable emission offsets at a specified ratio for the emissions from a new or modified source and any pre-existing cumulative increase minus any onsite contemporaneous emission reduction credits. Applies to emissions of POC, NO_X, PM10, and SO_2.

Phase II Acid Rain Facility
A facility that generates electricity for sale through fossil-fuel combustion and by virtue of certain other characteristics (defined in Regulation 2, Rule 6) is subject to Titles IV and V of the Clean Air Act.

POC
Precursor Organic Compounds

PM
Total Particulate Matter

PM10
Particulate matter with aerodynamic equivalent diameter of less than 10 microns

PSD
Prevention of Significant Deterioration. A federal program for permitting new and modified sources of 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.

SCR
A "selective catalytic reduction" unit is an abatement device that reduces NOx concentrations in the exhaust stream of a combustion device. SCRs utilize a catalyst, which operates at a specific temperature range, and injected ammonia to promote the conversion of NOx compounds to nitrogen gas.

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.

SO2
Sulfur dioxide

SO2 Bubble
An SO2 bubble is an overall cap on the SO2 emissions from a defined group of sources, or from an entire facility. SO2 bubbles are sometimes used at refineries because combustion sources are typically fired entirely or in part by "refinery fuel gas" (RFG), a waste gas product from refining operations. Thus, total SO2 emissions may be conveniently quantified by monitoring the total amount of RFG that is consumed, and the concentration of H2S and other sulfur compounds in the RFG.

SO3
Sulfur trioxide

THC
Total Hydrocarbons (NMHC + Methane)

therm
100,000 British Thermal Unit

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)

TRMP
Toxic Risk Management Plan

TSP
Total Suspended Particulate

TVP
True Vapor Pressure

VOC

Volatile Organic Compounds

Units of Measure:

bhp	=	brake-horsepower
Btu	=	British Thermal Unit
g	=	grams
gal	=	gallon
hp	=	horsepower
hr	=	hour
lb	=	pound
in	=	inches
max	=	maximum
m^2	=	square meter
min	=	minute
MM	=	million
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

Symbols:

$<$	=	less than
$>$	=	greater than
$\leq$	=	less than or equal to
$\geq$	=	greater than or equal to

APPENDIX C

Engineering Evaluation for Application 9805

CALPINE GILROY COGEN, L.P.
PLANT NO. 11180
APPLICATION NO. 9805

BACKGROUND

Calpine Gilroy Cogen, L.P. has applied for a permit to operate an existing standby fire pump powered by a diesel engine (S-6). The engine has been in operation since 1986 and was thus installed before May 17, 2000 when Regulation 1 and Regulation 2-1 were modified to require engines greater than 50 HP to require a Permit to Operate. As such, S-6 constitutes a Loss-Of-Exemption source not subject to Regulations 2-1-301 or 2-1-302 ("new" and "modified sources").

S-6 Emergency Standby Fire Pump: Diesel Engine; Make: Cummins; Model: NT-495-FP; Rated Horsepower: 170 HP

EMISSIONS

Emissions from S-6 do not need to be calculated since S-6 is not defined as a new or modified source pursuant to Regulation 2-1-232 and 2-1-234.

CUMULATIVE INCREASE

Emissions from S-6 do not count towards the facility's cumulative increase since S-6 is not defined as a new or modified source pursuant to Regulation 2-1-232 and 2-1-234.

BACT

Since S-6 is a loss-of-exemption source, it is not subject to BACT requirements pursuant to Regulation 2-2.

OFFSETS

Offsets are not required because S-6 is not a new or modified source pursuant to Regulation 2-1 and 2-2.

TOXIC RISK SCREEN ANALYSIS

A Toxic Risk Screen Analysis is not required for this source since S-6 is not a new or modified source and not subject to Regulation 2-1-316.

STATEMENT OF COMPLIANCE

S-6 is a loss-of-exemption standby fire pump installed before May 17, 2000. Pursuant to Regulation 9-8-110.2, S-6 is not subject to Regulations 9-8-301, 9-8-302, and 9-8-502. S-6 is subject to the monitoring and record keeping procedures described in Regulation 9-8-530, the

SO_2 limitations of Regulation 9-1-302 (ground level concentration) and 9-1-304 (0.5% by weight in fuel), and the Ringelmann No. 2 limitations of Regulation 6-303(emissions opacity limitations). S-6 is not subject to Regulation 9-8-330 because S-6 is less than 250 rated horsepower and was installed before May 17, 2000. Compliance with Regulation 9-1-304 is likely since California law mandates using diesel fuel with a 0.05% by weight sulfur.

Per Regulation 6, Section 303, a person shall not emit for a period or periods aggregating more than three minutes in any hour, a visible emission that is as dark or darker than No. 2 on the Ringelmann Chart, or of such opacity as to obscure an observer's view to an equivalent or greater degree, nor shall said emission, as perceived by an opacity sensing device in good working order, where such device is required by District regulations, be equal to or greater than 40% opacity. A properly maintained engine is expected to meet this.

This application is considered to be ministerial under the District's proposed CEQA guidelines (Regulation 2-1-311) and therefore is not subject to CEQA review. The engineering review for this project requires only the application of standard permit conditions and standard emission factors in accordance with Permit Handbook Chapter 2.3.

This source is not defined as a new or modified source and is therefore not subject to the public notification requirements of Regulation 2-1-412.

A toxic risk screening analysis is not required.

BACT, PSD, NSPS, and NESHAPS are not triggered.

PERMIT CONDITIONS

APPLICATION 9805; Calpine Gilroy Cogen, L.P.; PLANT 11180; CONDITIONS FOR S-6:

NONE

RECOMMENDATION

Waive Authority to Construct and issue a Permit to City of Gilroy for:

S-6 Emergency Standby Fire Pump: Diesel Engine; Make: Cummins; Model: NT-495-FP; Rated Horsepower: 170 HP

BY: ______________________________ ______

Xuna Cai Date

Air Quality Engineering Intern