JUN 29 2012

Certified Mail 7011 3500 0002 7298 7949
Return Receipt Requested

Glenn LaFevers
Southern California Gas Company
PO Box 818
Goleta, CA 93116-0818

FID: 01734
Permit: P7R 09584 - R4
SSID: 05019

Re: Final Part 70 Permit Renewal / Reevaluation 09584 - R4

Dear Mr. LaFevers:

Enclosed is the final Part 70 Permit Renewal / Reevaluation (PT-70/Reeval) No. 09584 - R4 for your natural gas storage facility at 1171 More Ranch Road in Goleta.

Pursuant to your letter dated June 26, 2012, we have revised permit condition 9.A.5 to retain the language from PT-70/Reeval 9584-R3.

Please carefully review the enclosed documents to ensure that they accurately describe your facility and that the conditions are acceptable to you. Note that your permitted emission limits may, in the future, be used to determine emission fees.

You should become familiar with all District rules pertaining to your facility. This permit does not relieve you of any requirements to obtain authority or permits from other governmental agencies.

This permit requires you to:

- Follow the conditions listed on your permit. Pay careful attention to the recordkeeping and reporting requirements.
- Ensure that a copy of the enclosed permit is posted or kept readily available near the permitted equipment.
- Promptly report changes in ownership, operator, or your mailing address to the District.

If you are not satisfied with the conditions of this permit, **you have thirty (30) days from the date of this issuance to appeal this permit to the Air Pollution Control District Hearing Board** (ref: California Health and Safety Code, §42302.1). Any contact with District staff to discuss the terms of this permit will not stop or alter the 30-day appeal period.

Please include the facility identification (FID) and permit numbers as shown at the top of this letter on all correspondence regarding this permit. If you have any questions, please contact Ben Ellenberger of my staff at (805) 961-8879.

Sincerely,

Michael Goldman, Manager
Engineering & Compliance Division

enc: Final PT-70/Reeval 09584 - R4
Final Permit Evaluation
Air Toxics "Hot Spots" Fact Sheet District Form 12B

cc: La Goleta 01734 Project File
ECD Chron File
Craig Strommen (Cover letter only)
Ben Ellenberger (Cover letter only)
Mr. Dennis Lowrey, Southern California Gas Company (Cover Letter Only)

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Santa Barbara County
Air Pollution Control District

Final

DISTRICT PERMIT to OPERATE No. 9584
And
RENEWAL PART 70 OPERATING PERMIT No. 9584

LA GOLETA FACILITY
SOUTHERN CALIFORNIA GAS COMPANY

1171 MORE ROAD
GOLETA, CA 93117

<u>OPERATOR</u>

Southern California Gas Company ("The Gas Company")

<u>OWNERSHIP</u>

Southern California Gas Company ("The Gas Company")

Santa Barbara County
Air Pollution Control District

June 2012

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
District	Santa Barbara County Air Pollution Control District
API	American Petroleum Institute
ASTM	American Society for Testing Materials
BACT	Best Available Control Technology
bpd	barrels per day (1 barrel = 42 gallons)
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
dscf	dry standard cubic foot
EU	emission unit
°F	degree Fahrenheit
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	inspection & maintenance
k	kilo (thousand)
l	liter
lb	pound
lbs/day	pounds per day
lbs/hr	pounds per hour
LACT	Lease Automatic Custody Transfer
LPG	liquid petroleum gas
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NEI	net emissions increase
NG	natural gas
NSPS	New Source Performance Standards
O2	oxygen
OCS	outer continental shelf
ppm(vd or w)	parts per million (volume dry or weight)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PRD	pressure relief device
PTO	Permit to Operate
RACT	Reasonably Available Control Technology
ROC	reactive organic compounds, same as VOC as used in this permit
RVP	Reid vapor pressure
scf	standard cubic foot
scfd (or scfm)	standard cubic feet per day (or per minute)
SIP	State Implementation Plan
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
THC	Total hydrocarbons
tpy, TPY	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system

1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District (District) is responsible for implementing all applicable federal, state and local air pollution requirements that affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 61, 63, 64, 68, 70 and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the District's Rules and Regulations. This is a combined permitting action that covers both the Federal Part 70 permit renewal (*Part 70 Operating Permit No. 9584*) as well as the District permit reevaluation (*Permit to Operate No. 9584*).

Part 70 Permitting. This permit is the third renewal of the Part 70 Permit for the SoCalGas La Goleta facility, and satisfies the permit issuance requirements of the District's Part 70 Operating Permit program. The District's triennial permit reevaluation has been combined with this Part 70 Permit renewal. SoCalGas La Goleta Plant comprises the *SoCalGas – La Goleta* stationary source (SSID = 5019), which is a major source for VOC[1], NO_x and CO. Conditions listed in this permit are based on federal, state or local rules and requirements. Sections 9.A, 9.B and 9.C of this permit are enforceable by the District, the USEPA and the public since these sections are federally enforceable under Part 70. Where any reference contained in Sections 9.A, 9.B or 9.C refers to any other part of this permit, that part of the permit referred to is federally enforceable. Conditions listed in Section 9.D are "District-only" enforceable.

Pursuant to the stated aims of Title V of the CAAA of 1990 (i.e., the Part 70 operating permit program), this permit has been designed to meet two objectives. First, compliance with all conditions in this permit would ensure compliance with all federally enforceable requirements for the facility. Next, the permit would be a comprehensive document to be used as a reference by the permittee, the regulatory agencies and the public to assess compliance.

Tailoring Rule. This reevaluation incorporates greenhouse gas emission calculations for the stationary source. On January 20, 2011, the District revised Rule 1301 to include greenhouse gases (GHGs) that are "subject to regulation" in the definition of "Regulated Air Pollutants". District Part 70 operating permits are being updated to incorporate the revised definition.

1.2 Facility Overview

1.2.1 Facility Overview: The La Goleta Stationary Source (SSID # 5019) is solely owned and operated by Southern California Gas Company (SoCalGas), a subsidiary of Sempra Energy, with the company regional headquarters located in downtown Los Angeles, CA. The source, consisting of the La Goleta facility (FID 1734) includes a number of natural gas compressors, a dehydration unit, ancillary units and a large underground natural gas storage reservoir. It is located in Goleta with a street address of 1171 More Road, Goleta, CA 93117 (postal address is P.O. Box 818, Goleta, CA 93116). For District regulatory purposes, the source location is in the Southern Zone

[1] VOC as defined in Regulation XIII has the same meaning as reactive organic compounds as defined in Rule 102. The term ROC shall be used throughout the remainder of this document, but where used in the context of the Part 70 regulation, the reader shall interpret the term as VOC.

of the Santa Barbara County[2]. The County is deemed a nonattainment area for the state 8-hour ozone standard, and the state annual and 24 hour PM_{10} standards. Figure 1-1 provides a site map depicting the source location and the main emission units.

The La Goleta facility was constructed in the 1940s. It consists of 21 underground gas storage wells, a dehydration plant consisting of a tank farm, odorization equipment, methanol storage tank, and external combustion equipment including flares, as well as a number of gas-fired internal combustion (IC) engines driving natural gas compressors and pumps. The La Goleta facility is permitted to withdraw natural gas from its underground storage at the rate of 680 MMscf/day, while its HC liquid (condensate, dry) production is restricted to 125,000 gallons per year. The facility consists of the following operating systems:

- Underground Natural Gas Storage and Retrieval system
- Sand and moisture separator system
- Gas Dehydration system
- Natural gas compression (using IC engines) and cooling system
- Tank farm for brine/condensate removal and storage
- Flares and Flare Gas Sulfur Removal System
- Gas shipping and metering system
- Electrical system /Micro-turbines
- Safety system
- Emergency fire pumps

Natural gas of PUC quality is compressed, cooled and stored in an underground depleted gas reservoir. During heavy demand the gas is withdrawn from the reservoir, separated from sand/moisture, dehydrated, odorized and routed to pipelines.

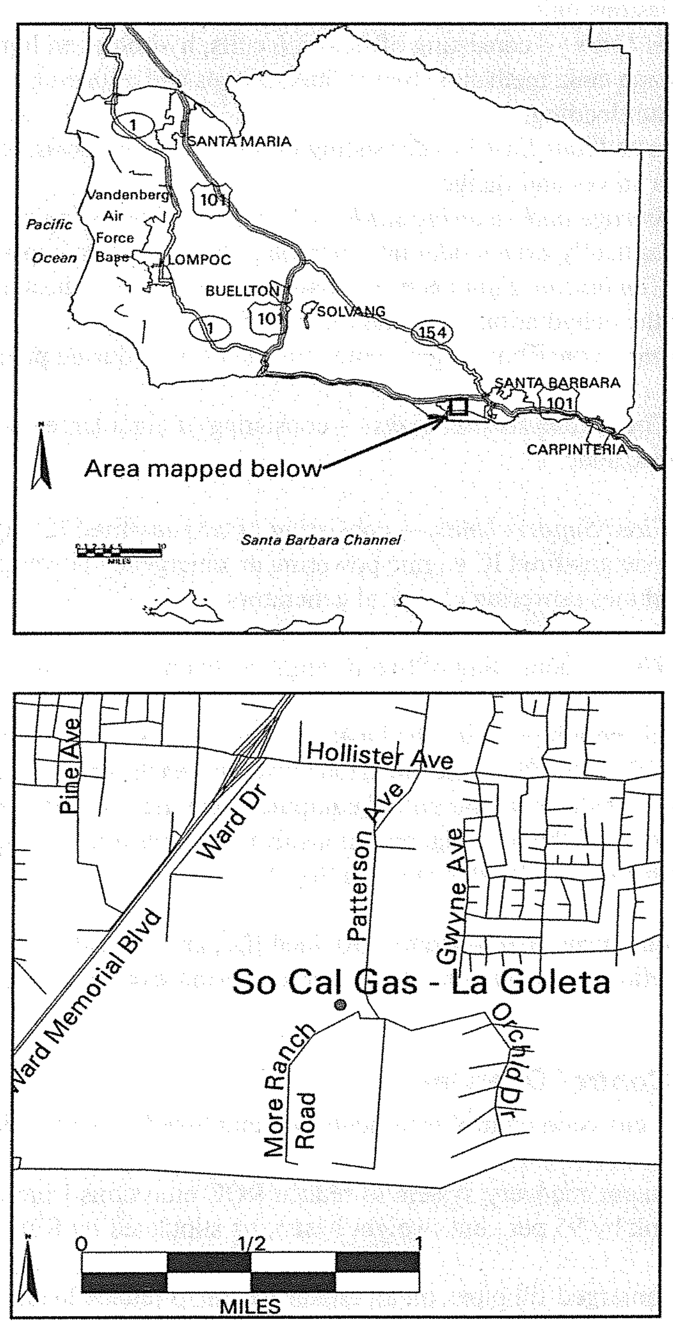
1.2.2 Facility Permit Overview: Since the last Part 70 renewal in June 2009, there has been one (1) permit action taken at this facility. It is listed below.

PTO 13479: To replace two existing glycol filters with two new glycol filters, one existing odorant injection pump and expansion tank with two new odorant injection pumps and expansion tanks, and add one new SULFATREAT vessel to be operated in parallel with an existing SULFATREAT vessel.

[2] District Rule 102, Definition: "Southern Zone"

Figure 1.1 Location Map for SoCalGas La Goleta facility

Southern California Gas - La Goleta



1.3 Emission Sources

Air pollutant emissions at the La Goleta facility come from the following equipment categories:

Dehydration Plant Unit 14 — consisting of glycol gas dehydration units including glycol contactors, filters, rectifiers, electric pumps and heat exchangers; Plant Unit 14 also includes the following emissions units:

Tank Farm Units — consisting of flotation cells, hydrocarbon liquid storage tanks, brine water storage tank, methanol storage tank, pumps and a loading rack for hydrocarbon liquid (condensate) loading;
Separators at Plant Unit 14 - consisting of high- and low-pressure separators and sand traps along with valves and flanges;
Odorant Storage and Metering station at Unit 14 – Consisting of an odorant storage tank, two pneumatically-driven odorant injection pumps, and two expansion tanks; and,
External Combustion Equipment – consisting of two (2) oil heaters and three (3) flares servicing the dehydration plant and the tank farm.
Gas Venting – consisting of gas vented through stacks during pipeline depressurization.

Natural Gas Fired Compression Units — consisting of eight large compressors driven by gas-fired IC engines; and,

Natural Gas Fired Support Units — consisting of two gas-fired IC engines powering air compressors, one gas-fired IC engine powering an emergency power generator, and four gas-fired micro turbines powering electrical generators.

Diesel-Fired Units – consisting of two IC engines that provide power to emergency fire pumps.

Section 4 of this permit provides the District's engineering analysis of these emission units. Section 5 describes the allowable emissions listed for each permitted equipment, the total permitted emissions from all permitted equipment, any net emissions increase for the facility due to the equipment and the potential emissions from non-permitted equipment. Potential HAP emissions estimates are also described in Section 5.

A list of all equipment, their operator-provided IDs, and individual unit ratings is provided in the Appendix, Section 10.5. Equipment considered permit-exempt by the District is listed in Section 10.6.

1.4 Emission Control Overview

The following emission control techniques are employed at the facility:

- Use of a vapor recovery system to reduce ROC emissions from the hydrocarbon liquid storage tank by 95 per cent (weight basis), as stipulated by Rule 326;

- Use of submerged fill pipes on all tanker trucks to reduce loading rack ROC emissions;

- Use of a flare relief system to combust hydrocarbon gases that would otherwise be released directly to the atmosphere; application of Rule 359 control measures to reduce flare emissions.

- Non-selective catalytic reduction (NSCR) units serving seven of the eight engines driving gas compressors. Air-fuel ratio (AFR) controllers assist all seven of the NSCR-controlled units.

- Sulfur removal units, using iron oxides and potassium permanganate, to reduce H_2S and mercaptans in the gaseous fuel going to the waste gas flares to permissible levels.

- Clean-burn technology controlling pollutant emissions from the lean burn engine, which powers the largest gas compressor.

- Designed 'low-NOx emissions (approx 10 ppmv)' for the micro-turbines, which are Air Resources Board certified for California's 'distributed generation program,' when fired on Public Utility Commission (PUC)-quality natural gas.

1.5 Offsets/Emission Reduction Credit Overview

The La Goleta plant facility does not require emission offsets. However, it provides NO_x emission reduction credits to the Point Arguello Project's Gaviota facility.

NOx emission reductions achieved by the NSCR units at seven gas compressors are used as NOx emission offsets. These emission reduction credits are valid for the life of the Point Arguello project. SoCalGas may use none of these emission reduction credits for other projects including those implemented, without prior approval by the District. Section 7 of this permit describes these emission reduction credits in detail.

1.6 Part 70 Operating Permit Overview

1.6.1. Federally-Enforceable Requirements: All federally enforceable requirements are listed in 40 CFR Part 70.2 (*Definitions*) under "applicable requirements." These include all SIP-approved District Rules, all conditions in the District-issued Authority to Construct permits and all conditions applicable to major sources under federally promulgated rules and regulations. All these requirements are enforceable by the public under CAAA. (*See Tables 3.1 and 3.2 for a list of federally enforceable requirements*).

1.6.2. Insignificant Emissions Units: Insignificant emission units are defined under District Rule 1301 as any regulated air pollutant emitted from the unit, excluding Hazardous Air Pollutants (HAPs), that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. Insignificant activities must be listed in the Part 70 application with supporting calculations. Applicable requirements may apply to insignificant units.

1.6.3. Federal Potential to Emit: The federal potential to emit (PTE) of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement which was in effect as of August 7, 1980, or (2) included in the 29-category source list specified in 40 CFR 70.2. The federal PTE does include all emissions from any insignificant emissions units. None of the equipment at this facility is subject to a federal NSPS/NESHAP requirement, nor is it included in the 29-category list, therefore the federal PTE does not include fugitive emissions. (*See Section 5.4 for the federal PTE for this source)*

1.6.4. Permit Shield: The operator of a major source may be granted a shield: (a) specifically stipulating any federally enforceable conditions that are no longer applicable to the source and (b) stating the reasons for such non-applicability. The permit shield must be based on a request from the source and its detailed review by the District. Permit shields cannot be granted indiscriminately with respect to all federal requirements. SoCalGas has not made a request for a permit shield.

1.6.5. Alternate Operating Scenarios: A major source may be permitted to operate under different operating scenarios, if appropriate descriptions of such scenarios are included in its Part 70 permit application and if such operations are allowed under federally-enforceable rules. SoCalGas made no request for permitted alternative operating scenarios.

1.6.6. Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on or before March 1st and September 1st, as specified in the permit. Each certification is signed by a "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit. *(See Section 1.6.10 below)*

1.6.7. Permit Reopening: Part 70 permits are re-opened and revised if the source becomes subject to a new rule or new permit conditions are necessary to ensure compliance with existing rules. The permits are also re-opened if they contain a material mistake or the emission limitations or other conditions are based on inaccurate permit application data.

1.6.8. MACT/Hazardous Air Pollutants (HAPs): Part 70 permits also regulate emission of HAPs from major sources through the imposition of maximum achievable control technology (MACT), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability. *(see Sections 3.2, 4.8 and 9.C)*.

1.6.9. Compliance Assurance Monitoring (CAM): The CAM rule became effective on April 22, 1998. This rule affects emission units at the source subject to a federally enforceable emission limit or standard that uses a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds. Sources subject to CAM Rule must submit a CAM Rule Compliance Plan along with their Part 70 operating permit renewal applications. All NSCR-controlled IC engines driving the compressors are subject to this Rule. *(see Sections 3.2.6, 4.9.3, Table 4.2 and 9.C.18)*

1.6.10 Responsible Official: The designated responsible official and their mailing address are:

Mr. Glenn La Fevers, Storage Operations Manager
Southern California Gas Company
P.O. Box 818
Goleta, California 93116-0818
Telephone: (805) 681-8068

2.0 Process Description

2.1 Process Summary

California Public Utilities Commission (CPUC) quality natural gas (meeting General Order 58-A standards) is purchased by SoCalGas from regional oil and gas producing companies. The gas comes to the La Goleta facility via pipelines. This natural gas is re-compressed to above 1300 psig by the eight (8) large IC engine driven compressors at the facility; after re-compression, the gas is stored in an underground depleted gas reservoir. During heavy demand periods natural gas is withdrawn from the sub-surface reservoir, its trapped impurities are removed, it is dehydrated, then it is transferred to pipelines.

Seven compressors, Units #2 through #8, are four-stroke rich burn units equipped with non-selective catalytic reduction (NSCR) for emission control. Unit #9, the largest compressor, is a two-stroke lean-burn unit equipped with 'Clean-Burn' technology to lower its emissions below the District requirements.

2.1.1 *Separators:* Separators at the dehydration facility remove free liquids and solids from the withdrawal gas stream. Sand causes erosion in the existing processing equipment and liquids, which reduces the efficiency of the glycol contactors.

Gas withdrawn from the field enters the dehydration plant through high-pressure separators, where sand and free liquids are removed. Gas then flows to low-pressure separators where any residual sand and free liquids are removed. The gas then flows to the glycol contactors for dehydration or directly to the transmission lines. Sand removed from the high-pressure separators is allowed to flow into a sand trap, which is emptied as necessary using a vacuum truck or manually. The free liquids removed from the separators are routed to the 'flotation cells' at the tank farm.

2.1.2 *Dehydration Plant 14:* The dehydration (Dehy) plant #14 is used to dehydrate gas withdrawn from the field. This gas contains hydrocarbon liquids and water and must be dried to pipeline quality before entering the transmission system. Gas withdrawn from the field enters the station through regulators where the pressure is reduced from 1300 - 1800 psig to 1,000 psig or below. The gas flows into glycol contactors where most of the free liquids are absorbed by the glycol. Along with the water, the glycol absorbs some entrained hydrocarbons and other impurities present in the gas. This rich glycol is then heated by heat exchangers to regenerate the glycol by driving off water, condensate, and other impurities. The regenerated lean glycol is then re-circulated into the contactors. The gas coming off from the contactor unit is commingled with a pre-determined amount of non-dehydrated gas to achieve the designed mix; and then routed into the supply system.

A condenser removes HC condensates from the glycol rectifier flash gas. The liquid removed from this gas is routed to the 'flotation cells' at the tank farm. The 'post-condenser' excess flash gas is treated for sulfur removal by the SULFATREAT units, and then burned off in the flare stacks serving the dehydration plant.

2.1.3 *Tank Farm:* Oily/Watery liquids collected from the gas in the separator traps and other units of the dehydration plant are pumped into one of the two flotation cells where the brine water and oily liquids are separated by gravity. After separation, the oily liquid is pumped into the hydrocarbon liquid storage tank and the brine is pumped into the brine water storage tank. The HC/brine is removed from the brine tank for disposal by a vacuum truck (highway tanker cargo carrier).

The HC condensate storage tank, the brine water storage tank and the flotation cells are closed and equipped with a vapor recovery system. When pressure builds in the tanks past a low-pressure set-point, a blower is activated and the excess gas is vented to a flare that is equipped with a continuous flame pilot.

2.1.4 *Methanol Storage Tank:* Methanol is used to prevent the formation of hydrates in the withdrawal gas pressure regulators. The hydrates can freeze to ice, which would occur during large pressure drops. Pneumatic pumps at the dehydration plant are used to inject methanol.

2.1.5 *Natural Gas Odorant and Metering Equipment:* A metering pump injects odorant 'Captan-50' (50% Tetrahydrothiophene and 50% t-Butyl Mercaptan) or 'Thiophane' into gas piped from the SoCalGas La Goleta underground storage and dehydration facility. Tanker trucks equipped with a vapor recovery system to reduce transfer emissions fill the odorant storage tank.

2.1.6 *Fugitive Components:* The fugitive components emit reactive organic compounds (ROC) from the valves, flanges, and fittings. Molecular composition of the ROC in the natural gas ranges to 13.3 percent, by weight, of the total hydrocarbon amount.

2.2 Support Systems

2.2.1 *Power Generation*: Four (4) natural gas fired micro-turbines powering generators provide power for the plant facility. La Goleta facility also employs one 160 hp gas-fired IC engine to provide emergency power to the office building at the facility. The gas-fired emergency equipment unit is restricted to 199 hours of operation annually, and is exempt from emission controls.

2.2.2 *Cooling Fans:* Cooling fans at the La Goleta facility, previously driven by gas-fired IC engines, are now driven by electric motors. Thus, these are no longer subject to any IC engine emission control rules.

2.2.3 *Support Operations:* Two (2) gas-fired IC engines, Units 4A and 5A, drive air compressors, and two (2) diesel-fired IC engines (units 12A and 13A) drive emergency firewater pumps to service equipment at the facility. The support units 4A and 5A are rated less than 50 horsepower and not subject to the District Rule 333 standards, and are not emissions-controlled. The support units 12A and 13A are exempt from Rule 333 per Rule 333.B.1.d and are not emissions-controlled.

2.2.4 *Heat Supply*: One hot oil (thermal fluid) heater rated at 3.5 MMBtu/hr and a similar 2.2 MMBtu/hr hot oil heater are used to provide heat to the heat exchangers in the dehydration process. Each unit is fired on PUC-quality natural gas. The 2.2 MMBtu/hr unit only operates when the 3.5 MMBtu/hr unit is not operating. There may be very brief overlap in operations of the two units but an analysis submitted by SoCalGas showed the combined operations cannot exceed 5 minutes, after which one of the two units is forced to shut down automatically. This analysis demonstrated the heat exchangers cannot handle heat input from both heaters simultaneously for more than 5 minutes without temperatures in the heat exchangers rising above design levels.

2.2.5 *Flares:* Three flares, each rated at 1.60 million BTU/hr, are used to flare off excess ROC from the tanks and dehydration plant. The constant-flame pilots at the flares are fired by PUC quality natural gas. The flare gas sulfur level is controlled by SULFATREAT units to below 239 ppmv.

2.2.6 *Loading Station:* A loading station facilitates periodic removal of liquids from the HC condensate storage tank into trucks. The trucks remove up to 125,000 gallons of the HC condensates annually.

2.2.7 *Flow Metering:* Flow metering is essential in the pre-sales blending of de-hydrated and non-dehydrated processed gases at the Gas Plant. All of the flow measurement devices (3419, 3433, 3445, 3464 and the four contactor outlets) are fitted with transmitters to meter and monitor volumetric flows via dynamic compensation procedures. Volumetric flow data is fed to a server computer at the Plant.

2.3 Maintenance/Degreasing Activities

2.3.1 *Paints and Coatings*: Maintenance painting at La Goleta facility is conducted on an intermittent basis. Normally, touch-up and equipment labeling or tagging is done with cans of spray paint.

2.3.2 *Solvent Usage*: Solvents not used for surface coating thinning may be used at the facility for daily operations. Usage includes cold solvent degreasing and wipe cleaning with rags.

2.4 Planned Process Turnarounds

Process turnarounds on the facility equipment are not planned/scheduled at La Goleta Plant.

2.5 Other Processes

Venting: Gas may be vented during pipeline depressurization. This gas is vented through a stack, but it is not flared and emissions of ROC are not controlled during this process. SoCalGas is limited to venting no more than 10 MMscf of gas per year.

2.6 Detailed Process Equipment Listing

Refer to the tables in Attachment 10.5 and 10.6 for a complete listing of all permitted and exempt emission units.

3.0 Regulatory Review

This Section identifies the federal, state and local rules and regulations applicable to the La Goleta facility.

3.1 Rule Exemptions Claimed

⇒ District Rule 202 (*Exemptions to Rule 201*): SoCalGas has requested and obtained permit exemptions for the following equipment items (*note that an exemption from permit does not grant relief from any applicable prohibitory rule unless specifically exempted by that prohibitory rule)*:

- Two (2) gas-fired IC engines, Waukesha VRG 220Us, 48 hp each (*202.F.1.f)*
- Two (2) glycol storage tanks, 2000 gallons capacity each and one (1) glycol run tank (*202.V.1*);
- Three (3) diesel tanks, two 110 gallons and one 600 gallons capacity (*202.V.2*);
- Three (3) Lube oil tanks, 5000 gallons capacity each (*202.V.3*)
- One (1) degreaser unit, JRI, Model TL 21, using non-ROC solvent (*202.U.2.c*);
- One (1) emergency electrical generator driven by a Waukesha F817GU gas-fired IC engine rated at 160 hp and operated < 200 hours/year (*202.F.1.d)*; and,
- One (1) glycol/glycol heat exchanger and one (1) glycol/oil heat exchanger (202.L.1).

⇒ District Rule 325 (*Crude Oil Production and Storage)*: Based on Rule 325.A, this 'post-custody-transfer' facility is not subject to Rule 325.

⇒ District Rule 326 (*Storage of Reactive Organic Compound Liquids)*: The pressurized glycol tanks and the methanol liquid storage tank at this facility are less than 5,000 gallons capacity. Similarly, the pressurized odorant storage tanks are less than 5,000 gallons capacity. Based on Rule 326.B.1.(a) and (b), these tanks are exempt from this rule

⇒ District Rule 331 (*Fugitive Emissions Inspection and Maintenance*): This facility, as currently configured, is not a 'gas production field' or a 'gas processing plant' as defined by Rule 331.C. Therefore this facility is not subject to Rule 331.

⇒ District Rule 333 (*Control of Emissions from Reciprocating Internal Combustion Engines*): Two (2) gas-fired IC engines driving two air compressors (4A & 5A) are rated less than 50 bhp, therefore they are not subject to Rule 333. The gas-fired emergency generator is exempt from Rule 333 based on Rule 333.B.1.b. The two diesel-fired emergency fire pumps are exempt from Rule 333 per Rule 333.B.1.d.

⇒ District Rule 342 (*Control of NO_x Emissions from Boilers, Steam Generators and Process Heaters*): The two hot oil heaters are not subject to Rule 342 since the heaters each have a heat input less than 5.0 MMBtu/hr.

⇒ District Rule 359 (*Flares and Thermal Oxidizers*): Each of the three flares is rated at 1.60 MMBtu/hour heat input. Based on Rule 359.B.3, the provisions of Rule 359 with the exception of Sections D.1 (*fuel sulfur content*), D.2 (*technology standards*), G (*monitoring*) and H (*reporting*), do not apply to the flares.

3.2 Compliance with Applicable Federal Rules and Regulations

3.2.1 <u>40 CFR Parts 51/52 {*New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration*)}</u>: The La Goleta facility was constructed and permitted prior to the applicability of these regulations. However, all permit modifications as of July 1979 are subject to District NSR requirements. Compliance with District Regulation VIII (*New Source Review*) ensures that future modifications to the facility will comply with these regulations.

3.2.2 <u>40 CFR Part 60 {*New Source Performance Standards*}</u>: None of the equipment in this permit is subject NSPS requirements.

3.2.3 <u>40 CFR Part 61 {*NESHAP*}</u>: None of the equipment in this permit is subject NESHAP requirements per 40 CFR Part 61.

3.2.4 <u>40 CFR Part 63 {*MACT*}</u>: On June 17, 1999, the USEPA promulgated Subpart HHH, a NESHAPS for Oil and Natural Gas Production and Natural Gas Transmission and Storage. The subpart applies to owners and operators of natural gas transmission and storage facilities that are major sources of HAPs. Based on District records, HAP emissions from the La Goleta Plant do not exceed the USEPA-defined 'major HAP source' threshold levels (see Section 5 for estimated HAP emissions). Therefore, this subpart does not apply.

3.2.5 <u>40 CFR Part 63 (MACT):</u> The rule requirements listed below are based on the current version of the NESHAP. The EPA has proposed revisions to the NESHAP that may revise some requirements. If the final revised rule conflicts with the summary listed below, the final revised rule will prevail.

The revised National Emission Standard for Hazardous Air Pollutants (NESHAP) for reciprocating internal combustion engines (RICE) was published in the Federal Register on January 18, 2008 as 40 CFR Part 63 Subpart ZZZZ. An affected source under the NESHAP is any existing, new, or reconstructed stationary RICE located at a major source or area source. Based on District records, HAP emissions from the La Goleta Plant do not exceed the USEPA-defined 'major HAP source' threshold levels (see Section 5 for estimated HAP emissions). Therefore, the La Goleta Plant is currently considered an area HAP source.

A stationary RICE located at an area source of HAP emissions is new if construction or reconstruction commenced on or after June 12, 2006. Reconstruction is defined in 40 CFR 63.2 as the replacement of components to such an extent that the fixed capital costs of the new components exceeds 50 percent of the fixed capital cost that would be required to construct a comparable new source. All of the engines at the facility were in place before June 12, 2006. The cost of ongoing maintenance on each engine does not exceed 50 percent of the fixed capital cost that would be required to construct a comparable new engine, therefore all of the RICEs at the facility are considered existing engines for the purpose of this Subpart.

Existing emergency standby compression ignition RICE at area sources of HAP emissions (the two E/S DICE firewater pumps) must comply with the applicable emission and operating limits by no later than May 3, 2013. The following operating requirements apply:

(1) change the oil and filter every 500 hours of operation or annually, whichever comes first;

(2) inspect the air cleaner every 1,000 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

Existing emergency standby spark ignition RICE at area sources of HAP emissions (the Waukesha emergency electrical generator) must comply with the applicable emission and operating limits by no later than October 19, 2013. The following operating requirements apply:

(1) change the oil and filter every 500 hours of operation or annually, whichever comes first;

(2) inspect spark plugs every 1,000 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 500 hours of operation or annually, whichever comes first.

Existing non-emergency, non-black start 2SLB spark ignition RICE at area sources of HAP emissions (the Cooper-Bessemer) must comply with the applicable emission and operating limits by no later than October 19, 2013. The following operating requirements apply:

(1) change the oil and filter every 4,320 hours of operation or annually, whichever comes first;

(2) inspect spark plugs every 4,320 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 4,320 hours of operation or annually, whichever comes first.

Existing non-emergency, non-black start 4SRB spark ignition RICE rated less than or equal to 500 hp at area sources of HAP emissions (the two Waukesha air compressors) must comply with the applicable emission and operating limits by no later than October 19, 2013. The following operating requirements apply:

(1) change the oil and filter every 1,440 hours of operation or annually, whichever comes first;

(2) inspect spark plugs every 1,440 hours of operation or annually, whichever comes first;

(3) inspect all hoses and belts every 1,440 hours of operation or annually, whichever comes first.

For any engine subject to oil change requirements, the owner or operator has the option of utilizing an oil analysis program in order to extend the specified oil change interval.

Existing non-emergency, non-black start 4SRB spark ignition RICE rated greater than 500 hp at area sources of HAP emissions (the eight Ingersoll-Rand gas compressors) must comply with the applicable emission and operating limits by no later than October 19, 2013. The following emission limits apply:

(1) Limit concentration of formaldehyde in the exhaust to 2.7 ppmvd @ 15 percent O_2; or

(2) Reduce formaldehyde emissions by 76 percent or more.

The operator must:

(1) Maintain the catalyst so that the pressure drop across the catalyst does not change by more than 2 inches of water from the pressure drop across the catalyst measured during the initial performance test when the engine is operated at 100 percent load plus or minus 10 percent; and

(2) Maintain the catalyst inlet temperature greater than or equal to 750 degrees F and less than or equal to 1,250 degrees F.

To demonstrate continuous compliance with the operating parameters, the operator must:

(1) Measure the pressure drop across the catalyst once per month; and

(2) Collect the catalyst inlet temperature data and reduce the data to 4-hour rolling averages.

The operator must conduct an initial performance test within 180 days after the compliance date (no later than April 17, 2014) and subsequent performance tests every 8,760 hours of operation, or every three years, whichever comes first.

3.2.6 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998. This rule affects emission units at the source subject to a federally enforceable emission limit or standard that uses a control device to comply with the emission standard, and either pre-control or post-control emissions exceed the Part 70 source emission thresholds. Compliance with this rule was evaluated and it was determined that all IC engines driving gas compressors at this facility and equipped with NSCR devices are subject to Compliance Assurance Monitoring (CAM) [*Ref: 40 CFR 64.2(a)*]. SoCalGas submitted a CAM Plan in August 2002, and has updated it periodically. See Section 4.9.3 (along with Table 4.2) and 9.C.1(c)(ii) of this permit for further detailed information on the CAM Plan requirements.

3.2.7 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to the La Goleta Plant. Table 3.1 lists the federally enforceable District promulgated rules that are "generic" and apply to the EOF. Table 3.2 lists the federally enforceable District promulgated rules that are "unit-specific" that apply to the EOF. These tables are based on data available from the District's administrative files, from SoCalGas Part 70 Operating Permit No. 9584-R3 issued in June 2009 and their renewal application submitted in December 2011. Table 3.4 includes the District's adoption dates of these rules.

In its Part 70 permit application, SoCalGas certified compliance with all existing District rules and permit conditions. This certification is also required of SoCalGas semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that SoCalGas complies with the provisions of all applicable Subparts.

3.3 Compliance with Applicable State Rules and Regulations

3.3.1 Division 26. Air Resources {California Health & Safety Code}: The administrative provisions of the Health & Safety Code apply to this facility and will be enforced by the District. These provisions are District-enforceable only.

3.3.2 California Code of Regulations, Title 17, Sub-Chapter 6, Sections 92000 through 92530: These sections specify the standards by which abrasive blasting activities are governed throughout the State. All abrasive blasting activities at the La Goleta Plant are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are District-enforceable only. However, CAC Title 17 does not preempt enforcement of any SIP-approved rules that may be applicable to emissions from abrasive blasting activities.

3.3.3 California Code of Regulations, Title 17, Section 93115: This section is the airborne toxic control measure (ATCM) to reduce diesel particulate matter (PM) and criteria pollutant emissions from stationary diesel-fueled compression ignition (CI) engines. Its provisions apply to any stationary,_industrial CI engine operated in California with a rated brake horsepower greater than 50 (>50 bhp). Portable or off-road l IC engines not integral to the stationary source operations are exempt from this ATCM. The two emergency standby firewater pump engines are subject to the ATCM. Per section 93115.3(n) the engines are exempt from the maintenance and testing hours limits of the ATCM, as long as they only operate the number of hours necessary to comply with the testing requirements of the NFPA Standard 25.

3.4 Compliance with Applicable Local Rules and Regulations

3.4.1 The last facility inspections occurred on December 28, 2011. The inspector reported the facility to be in compliance with all District rules and PTO conditions.

3.4.2 Rules Requiring Further Discussion: This section provides a more detailed discussion regarding the applicability and compliance of certain rules. The following is a rule-by-rule evaluation of compliance for La Goleta facility:

Rule 210 - Fees: Pursuant to Section G, District permits are reevaluated every three years. This includes the re-issuance of the underlying permit to operate. Also included are the PTO fees. The fees for this facility are based on the District Rule 210, Fee Schedule A. Attachment 10.3 presents the fee calculations for the reevaluated permit. La Goleta Plant was scheduled for re-evaluation in June 2012 and the 3-year fees are based on this date.

Rule 301 - Circumvention: This rule prohibits the concealment of any activity that would otherwise constitute a violation of Division 26 (Air Resources) of the California H&SC and the District rules and regulations. To the best of the District's knowledge, SoCalGas is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the flares and all gas or diesel-fired piston internal combustion engines. Compliance will be assured by requiring all engines to be maintained according to manufacturer maintenance schedules, and through visible emissions monitoring requirements in Condition 9.B.2. Rule 359 addresses the need for the flares to operate in a smokeless fashion.

Rule 303 - Nuisance: This rule prohibits the plant operator from causing a public nuisance due to the discharge of air contaminants. SoCalGas will maintain complaint logs on-site to record any nuisance complaints reported to the District, which requires SoCalGas mitigation action.

Rule 305 - Particulate Matter, Southern Zone: La Goleta Plant is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of specified concentrations measured in gr/scf. The maximum allowable concentrations are determined as a function of volumetric discharge, measured in scfm, and are listed in Table 305(a) of the rule (*lowest allowable limit is 0.01 gr/dscf*). Sources subject to this rule include: the flares, all IC engines, including diesel-fired units, and the micro-turbine generators. Compliance with PM_{10} emission limits is usually met by all natural gas-fired devices (uncontrolled PM_{10} emission factor equivalent to 0.007 gr/dscf). Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by requiring all engines to be maintained according to a District-approved *IC Engine Particulate Matter Operation and Maintenance Plan.*

Rule 309 - Specific Contaminants: Under Section A, no source may discharge sulfur compounds and combustion contaminants in excess of 0.2 percent as SO_2 (by volume) and 0.3 gr/scf (at 12% CO_2) respectively. Sulfur emissions due to the combustion of waste gases in the flares should comply with the SO_2 limit due to stoichiometric combustion requirements. All diesel powered piston IC engines have the potential to exceed the combustion contaminant limit if not properly maintained (see discussion on Rule 305 above for compliance).

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted in La Goleta facility to 0.5 percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H_2S) {or 239 ppmv} for gaseous fuels. Natural gas fuel used at the facility is of PUC quality (4 ppmv H_2S); gaseous fuel combusted at the flares are controlled to 239 ppmv H_2S content using sulfur removal units.

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the discharge of emissions of both photochemically and non-photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used at the La Goleta Plant during normal operations for degreasing by wipe cleaning and for use in paints and coatings in maintenance operations. There is the potential to exceed the limits under Section B.2 during significant surface coating activities. SoCalGas will be required to maintain records to ensure compliance with this rule.

Rule 321 – Solvent Cleaning Machines and Solvent Cleaning: This rule sets equipment and operational standards for degreasers using organic solvents. SoCalGas uses a degreaser not subject to this rule, based on its non-ROC solvent usage.

Rule 323 - Architectural Coatings: This rule sets standards for the application of surface coatings. The primary coating standard that will apply to the La Goleta Plant is for Industrial Maintenance Coatings that have a limit of 250 gram ROC per liter of coating, as applied.

SoCalGas is required to comply with the Administrative requirements under Section F for each container at the La Goleta Plant.

Rule 324 - Disposal and Evaporation of Solvents: This rule prohibits any source from disposing more than one and a half gallons of any photochemically reactive solvent per day by means that will allow the evaporation of the solvent to the atmosphere. SoCalGas will be required to maintain records to ensure compliance with this rule.

Rule 326 – Storage of Reactive Organic Compound Liquids: This rule, adopted December 14, 1993, applies to equipment used to store ROC liquids with a vapor pressure greater than 0.5 psia. The primary requirements of this rule are under Sections D and E. The flotation cells and the HC condensate storage tank (Device ID #s 1217, 1219, and 1220) are subject to the requirements of this rule. SoCalGas complies with this rule by using a District-approved vapor recovery system on all three tanks.

Rule 330 – Surface Coating of Metal Parts and Products: This rule applies to the use of surface coatings for metal parts and products. It does not apply to coating operations which are subject to Rule 323.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater that are fueled by liquid or gaseous fuels. As stated above, the emergency standby DICEs powering the firewater pumps and the emergency standby generator are exempt from the requirements of Rule 333. The IC engines powering the eight compressors are subject to the NO_x, CO and ROC standards under Section E for non-cyclic engines. Unit # 9 is a lean-burn engine; the other seven engines subject to the rule are rich-burn engines. Ongoing compliance will be achieved through implementation of the District-approved *Inspection and Maintenance Plan* and through biennial source testing for Unit #9 and, annual source testing for Units # 2-8.

Rule 346 - Loading of Organic Liquids: This rule applies to the transfer of organic liquids into an organic liquid cargo vessel. For this rule only, an organic liquid cargo vessel is defined as a truck, trailer or railroad car. The loading station operated at the La Goleta facility is subject to this rule. Compliance with the rule requirements is met since submerged fill pipes are used. The facility throughput is limited to less than 20,000 gallons per day and 150,000 gallons per year so a vapor recovery system is not required for the loading station.

Rule 352 – Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters: This rule applies to new water heaters rated less than 75,000 Btu/hr and new fan-type central furnaces. It requires the certification of newly installed units.

Rule 353 – Adhesives and Sealants: This rule applies to the use of adhesives and sealants. Compliance with this rule will be achieved through use of Rule 353-allowable sealants and adhesives and through proper record keeping per Rule 353 addressing the use of adhesives and sealants at the facility.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. Compliance with this rule has been documented. A detailed review of compliance issues is as follows:

- D.1 - Sulfur Content in Gaseous Fuels: Part (a) limits the total sulfur content of all planned flaring from South County flares to 15 gr/100 cubic feet (239 ppmv) calculated as H_2S at standard conditions. Compliance with this rule is anticipated since SoCalGas has installed a sulfur removal system upstream of the flare, and periodic monitoring of the system is required per Section 9.C.4 provisions.
- D.2 - Technology Based Standard: Requires all flares to be smokeless and sets pilot flame requirements. The flares at La Goleta facility are in compliance with this section.

Rule 360 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers: This rule applies to any water heater, boiler, steam generator, or process heater rated from 75,000 Btu/hour to 2 MMBtu/hr. Any unit manufactured after October 17, 2003 must be certified to meet the NO_x emission limits of the rule. If SoCalGas installs a new unit it must comply with this rule.

Rule 361- Small Boilers, Steam Generators, and Process Heaters: This rule applies to process heaters rated between 2 and 5 MMBtu/hr. A process heater is defined in Rule 361 as any external combustion equipment which transfers heat from combustion gases to water or process streams. The heaters use oil to heat a rich glycol process stream, therefore the units are defined as process heaters per Rule 361.

The emission standards of Rule 361 do not apply to existing units until 2020. Therefore no modifications to the units, or monitoring, or source testing is required at this time. SoCalGas will be required to comply with the requirements for existing units for HOH#1 and HOH #2 (device IDs 001214 and 107535) by the deadlines established in the rule.

Rule 505 - Breakdown Conditions: This rule describes the procedures that SoCalGas must follow when a breakdown condition occurs to any emissions unit associated with La Goleta facility. A breakdown condition is defined as an unforeseeable failure or malfunction of (1) any air pollution control equipment or related operating equipment which causes a violation of an emission limitation or restriction prescribed in the District Rules and Regulations, or by State law, or (2) any in-stack continuous monitoring equipment, provided such failure or malfunction:

a. Is not the result of neglect or disregard of any air pollution control law or rule or regulation;
b. Is not the result of an intentional or negligent act or omission on the part of the owner or operator;
c. Is not the result of improper maintenance;
d. Does not constitute a nuisance as defined in Section 41700 of the Health and Safety Code;
e. Is not a recurrent breakdown of the same equipment.

Rule 603 - Emergency Episode Plans: Section A of this rule requires the submittal of *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide or particulate matter. SoCalGas submitted such a plan December 2008.

Rule 810 – Federal Prevention of Significant Deterioration: This rule was adopted January 20, 2011 to incorporate the federal Prevention of Significant Deterioration rule requirements into the District's rules and regulations. Future projects at the facility will be evaluated to determine whether they constitute a new major stationary source or a major modification.

3.5 *Compliance History*

This section contains a summary of the compliance history for this facility and was obtained from documentation contained in the District's administrative file.

3.5.1 Violations: One (1) Notice of Violation (NOV) has been issued since June 18, 2009:

NOV 9434: Issued 4/21/2010. Specifically, for failure to pass annual source test. The catalyst was changed; the engine was tested and demonstrated compliance on the same day. The catalyst had only operated for 150 hours before failure and a subsequent investigation determined that the catalyst formulation had been changed without SoCal Gas's knowledge. The NOV was subsequently rescinded.

3.5.2 Significant Historical Hearing Board Actions/NOVs: There are no significant historical Hearing Board actions or NOVs.

Table 3.1 - Generic Federally-Enforceable District Rules

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 101: Compliance by Existing Installations	All emission units	Emission of pollutants
RULE 102: Definitions	All emission units	Emission of pollutants
RULE 103: Severability	All emission units	Emission of pollutants
RULE 201: Permits Required	All emission units	Emission of pollutants
RULE 202: Exemptions to Rule 201	Applicable emission units, as listed in Part 70 renewal	Insignificant activities/emissions, per size/rating/function
RULE 203: Transfer	All emission units	Change of ownership
RULE 204: Applications	All emission units	Addition of new equipment or modification to existing equipment.
RULE 205: Standards for Granting Permits	All emission units	Emission of pollutants
RULE 206: Conditional Approval of Authority to Construct or Permit to Operate	All emission units	Applicability of relevant Rules
RULE 207: Denial of Applications	All emission units	Applicability of relevant Rules
RULE 208: Action on Applications - Time Limits	All emission units. Not applicable to Part 70 permit applications.	Addition of new equipment or modification to existing equipment.
RULE 212: Emission Statements	All emission units	Administrative
RULE 301: Circumvention	All emission units	Any pollutant emission
RULE 302 : Visible Emissions	All emission units	Particulate matter emissions
RULE 303: Nuisance	All emission units	Emissions that can injure, damage or offend.
RULE 305: PM Concentration - South Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminant emission
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process operations.
RULE 321: Solvent Cleaning Machines and Solvent Cleaning	Emission units using solvents	Solvent used in process operations.
RULE 323: Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 324: Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.
RULE 353: Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.
RULE 505.A, B1, D: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	SoCalGas – La Goleta is a major source.
REGULATION VIII: New Source Review	All emission units	Addition of new equipment of modification to existing equipment. Applications to generate ERC Certificates.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	SoCalGas – La Goleta is a major source.

Table 3.2 - Unit-Specific Federally enforceable District Rules

Unit-Specific Requirements	Affected Emission Units	Basis for Applicability
RULE 326: Storage of Reactive Organic Compound Liquids.	Tanks, Sumps, Vessels.	All reactive organic compound liquids storage units
RULE 333: Control of Emissions from Reciprocating IC Engines	IC engines at the facility driving compressors and emergency fire pumps.	Stationary IC engines exceeding a rating of 50 hp
RULE 346: Loading of Organic Liquids	Loading rack at the facility.	Rate/capacity triggering applicability
RULE 359: Flares and Thermal Oxidizers	Flares.	Flares, non-exempt from permitting.
RULE 360: Emissions of Oxides of Nitrogen from Large Water Boilers and Small Boilers	Any new small boiler installed at the facility.	New units rated from 75,000 Btu/hr to 2.000 MMBtu/hr
RULE 361: Small Boilers, Steam Generators, and Process Heaters	Hot Oil Heaters.	Heat input > 2.000 MMBtu/hr and < 5.000 MMBtu/hr

Table 3.3 - Non-Federally-Enforceable District Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Odorous organic sulfides	Liquid hydrocarbon tanks	Potential odor problems
RULE 352: Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	New water heaters and furnaces	Upon installation
RULES 501-504: Variance Rules	All emission units	Administrative
RULE 505.B2, B3, C, E, F, G: Breakdown Conditions	All emission units	Breakdowns where permit/rule limits are not complied with.
RULES 506-519: Variance Rules	All emission units	Administrative

Table 3.4 - Adoption Dates of District Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 1981
Rule 102	Definitions	March 17, 2011
Rule 103	Severability	October 23, 1978
Rule 201	Permits Required	June 19, 2008
Rule 202	Exemptions to Rule 201	March 17, 2011
Rule 203	Transfer	April 17, 1997
Rule 204	Applications	April 17, 1997
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of Authority to Construct or Permit to Operate	October 15, 1991
Rule 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978
Rule 302	Visible Emissions	June 1981
Rule 303	Nuisance	October 23, 1978
Rule 305	Particulate Matter Concentration - Southern Zone	October 23, 1978
Rule 309	Specific Contaminants	October 23, 1978
Rule 310	Odorous Organic Sulfides	October 23, 1978
Rule 311	Sulfur Content of Fuels	October 23, 1978
Rule 317	Organic Solvents	October 23, 1978
Rule 321	Solvent Cleaning Operations	September 20, 2010
Rule 323	Architectural Coatings	November 15, 2001
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	July 19, 2001
Rule 326	Storage of Reactive Organic Compound Liquids	January 18, 2001
Rule 333	Control of Emissions from Reciprocating Internal Combustion Engines	June 19, 2008

Rule No.	Rule Name	Adoption Date
Rule 343	Petroleum Storage Tank Degassing	December 14, 1993
Rule 346	Loading of Organic Liquid Cargo Vessels	January 18, 2001
Rule 352	Natural Gas-Fired Fan-Type Central Furnaces and Small Water Heaters	October 20, 2011
Rule 353	Adhesives and Sealants	August 19, 1999
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
Rule 360	Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers	October 17, 2002
Rule 361	Small Boilers, Steam Generators, and Process Heaters	January 17, 2008
Rule 505	Breakdown Conditions (Section A, B1 and D)	October 23, 1978
Rule 603	Emergency Episode Plans	June 15, 1981
Rule 801	New Source Review	April 17, 1997
Rule 802	Nonattainment Review	April 17, 1997
Rule 803	Prevention of Significant Deterioration	April 17, 1997
Rule 804	Emission Offsets	April 17, 1997
Rule 805	Air Quality Impact and Modeling	April 17, 1997
Rule 806	Emission Reduction Credits	April 17, 1997
Rule 808	New Source Review for Major Sources of Hazardous Air Pollutants	May 20, 1999
Rule 810	Federal Prevention of Significant Deterioration	January 20, 2011
Rule 1001	National Emission Standards for Hazardous Air Pollutants	October 26, 1993
Rule 1301	General Information	January 20, 2011
Rule 1302	Permit Application	November 9, 1993
Rule 1303	Permits	January 18, 2001
Rule 1304	Issuance, Renewal, Modification and Reopening	January 18, 2001
Rule 1305	Enforcement	November 9, 1993

4.0 Engineering Analysis

4.1 General

The engineering analyses performed for this permit were limited to the review of:

- facility process flow diagrams
- emission factors and calculation methods for each emissions unit
- emission control equipment (including RACT, BACT, NSPS, NESHAP, MACT)
- emission source testing, sampling, CAM
- process monitors needed to ensure compliance

Unless noted otherwise, default ROC/THC reactivity profiles from the District's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 4/01/03 (ver. 1.3) was used to determine non-methane, non-ethane fraction of THC.

4.2 Stationary Internal Combustion Sources

The stationary source has a total of thirteen IC engines at the facility, eleven gas-fired and two diesel-fired, as described below, as well as four micro-turbine generators.

4.2.1 *Gas-Fired Piston IC Engines with Emissions Control:* IC engines operating at the La Goleta Plant and equipped with emissions control comprise of the following:

> Seven (7) rich-burn, non-cyclic, natural gas-fired Ingersoll-Rand IC engines (four (4) Model LVG-82s and three (3) Model KVG-62s), each equipped with a non-selective catalytic reduction (NSCR) system and an automatic air-fuel ratio controller, and each driving a gas compressor;
>
> One (1) lean-burn, non-cyclic, two-stroke, natural gas-fired Cooper Bessemer Model GMV-10C engine, equipped with "Clean-Burn" emissions control technology (using leaner air-fuel ratio, turbo-charger unit, 'jet cell' fuel ignitors and an AFRC unit regulating the turbocharger), driving a gas compressor;

The seven Ingersoll-Rand engines have provided emission reduction credits (ERCs) since 1989 to the Point Arguello project. Their stipulated NO_x emission factor is 0.324 lb/MMBtu, which is higher than the emission factor which corresponds to 50 ppmv @ 15% O_2, but the engines may emit 0.324 lb NO_x/MMBtu and still comply with Rule 333 as long as they can demonstrate 90% control. The ROC emission factor is 0.32 lb/MMBtu, which corresponds to 250 ppmv @ 15% O_2 and a molecular weight of 16 lb/lb-mol for the organic compounds, and the CO emission factor is 3.815 lb/MMBtu, which corresponds to 1,700 ppmvd @ 15% O_2.

The Cooper Bessemer engine operates with a permitted NO_x emission factor of 125 ppmvd @ 15% oxygen, ROC emission factor of 750 ppmv @ 15% oxygen, and CO emission factor of 4,500 ppmvd @ 15% oxygen.

Sulfur dioxide emissions from all engines are based on mass balance calculations, assuming maximum 80 ppmv total sulfur content for fuel. The PM_{10} emissions from all engines are based on the corresponding emission factors listed in USEPA's AP-42 Table 3.2-3. The emission factors and heat input rate are calculated in appendix 10.1. The calculation methodology is as follows:

$$ER = (EF \ x \ Q \ x \ HPP)$$

<u>where</u>: ER = emission rate (lb/period)
EF = pollutant specific emission factor (lb/MMBtu)
Q = heat input rate (MMBtu/hr)
HPP = operating hours per time period (hrs/period)

The emission factor and heat input rate are based on the higher heating value (HHV) of the fuel.

4.2.2 *Diesel Engines:* Diesel fired IC engines operating at the La Goleta Plant:

Two (2) emergency standby Cummins V 378 F2 engines, driving fire pumps, each rated at 133 bhp.

The emission factors are based on the engine's rating and age. The NOx, CO, ROC and PM10 emissions factors were obtained from USEPA's AP-42 Table 3.3-1. The SOx emissions factor was obtained from USEPA's AP-42 Table 3.3-2 and assumed 0.0015% by weight of sulfur in the diesel fuel. Daily operations are limited to 2 hours and annual operations are limited to 20 hours for maintenance and testing. Emergency use is unlimited. The calculation methodology is as follows:

E1, lb/day = Engine Rating (bhp) * EF (g/bhp-hr) * Daily Hours (hr/day) * (lb/453.6 g)
E2, tpy = Engine Rating (bhp) * EF (g/bhp-hr) * Annual Hours (hr/yr) * (lb/453.6 g) * (ton/2000 lb)

4.2.3 *Gas-Fired Piston IC Engines Without Emissions Control*: Natural gas fired District-permit-exempt IC engines operating at the La Goleta Plant:

Two (2) rich-burn, non-cyclic, natural gas-fired Waukesha IC engines (two VRG 220U's driving air compressors; and,
One (1) emergency gas-fired electrical generator driven by a Waukesha F817GU IC engine rated at 160 hp.

The NO_x,, ROC, CO and PM_{10} emission factors for these units correspond to those listed in USEPA's AP-42 (*Air Chief, Version 9.0, 10/02*). Sulfur dioxide emissions from the engines are based on mass balance calculations, assuming maximum 80 ppmv total sulfur content of fuel. The calculation methodology is as follows:

$$ER = (EF \ x \ Q \ x \ HPP)$$

where: ER = emission rate (lb/period)
EF = pollutant specific emission factor (lb/MMBtu)
Q = heat input rate (MMBtu/hr)
HPP = operating hours per time period (hrs/period)

The emission factor and heat input rate are based on the higher heating value (HHV) of the fuel.

4.2.4 *Micro-Turbine Generators:* Four (4) natural gas-fired micro-turbine generators are used for electrical power generation.

The NOx, CO and ROC emission factors for these units correspond to those listed in CARB DG-002. These are 0.5 lb/MW-hr for NO_x, 6 lb/MW-hr for CO, and 1 lb/MW-hr for ROC. Sulfur dioxide emissions from the engines are based on mass balance calculations, assuming maximum 80 ppmv total sulfur content of fuel. The emission factors are calculated in appendix 10.2. The calculation methodology is as follows:

$$ER = [\ (EF \ x\ Q\ x\ HPP)\ ]$$

where:	ER =	emission rate (lb/period)
	EF =	pollutant specific emission factor (lb/MMBtu)
	Q =	heat input rate (MMBtu/hr)
	HPP =	operating hours per time period (hrs/period)

The emission factor and heat input rate are based on the higher heating value (HHV) of the fuel.

4.3 Stationary External Combustion Sources

The stationary external combustion sources at La Goleta facility are the two hot oil heaters and the three flares. None of these equipment items are subject to any mass emission or emission concentration limits specified in the relevant District Rules 342, 359, and 361. However, the flares are subject to the operational standards listed in Rule 359.

4.3.1 *Gas-Fired Heaters*: The two oil heaters are PUC-quality natural gas-fired. The heaters supply hot oil for dehydration facility operations including glycol heat exchanger operations. The hot oil heater manufactured by Fulton Thermal Corporation is rated at 3.5 MMBtu/hour heat input. The hot oil heater manufactured by American Heating Company is rated at 2.2 MMBtu/hour heat input. The calculation methodology for these combustion units is:

$$ER = EF\ x\ Q$$

where:	ER =	emission rate (lb/period)
	EF =	pollutant specific emission factor (lb/MMBtu)
	Q =	heat input rate (MMBtu/hr)

The emission factors for NO_x, CO, ROC, PM and PM_{10} are based on AP-42 emission factors for small natural gas-fired boilers (Tables 1.4-1 and 1.4-2). The SO_x emission factor is based on the combustion of PUC natural gas.

4.3.2 *Flare Relief System*: The flare relief system consists of three 1.60 MMBtu flares which connect to the tank farm and the glycol system. Both planned and unplanned flaring events occur. Emission factors for NOx, CO and ROC are based on the USEPA AP-42, Table 11.5-1 (9/91). PM emission factors are based on a District flare study. Sulfur oxide emissions are based on mass balance calculations assuming both planned and pilot/purge sulfur levels at 80 ppmv and unplanned flaring sulfur levels at 239 ppmv. The emissions for both planned and unplanned flaring events are calculated. The SO_x emission factor is determined using the equation: (0.169) (ppmv S)/ (HHV). The calculation methodology for the flares is:

$$ER = EF \times Q$$

where:	ER =	emission rate (lb/period)
	EF =	pollutant specific emission factor (lb/MMBtu)
	Q =	heat input rate (MMBtu/hr)

4.4 Fugitive Hydrocarbon Sources

4.4.1 Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been assigned emission factors pursuant to District P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility Component Counts - Modified for Revised ROC Definition*). The component leak-path was counted consistent with P&P 6100.061. This leak-path count is not the same as the component count required by District Rule 331. Only gas/light liquid side components are in service at this facility.

The number of emission leak-paths was determined by the operator. The leak path count is documented in Table 5.1-1. The calculation methodology for the fugitive emissions is:

$$ER = [(EF \times CLP \div 24) \times (1 - CE) \times (HPP)]$$

where:	ER =	emission rate (lb/period)
	EF =	ROC emission factor (lb/clp-day)
	CLP =	component leak-path (clp)
	CE =	control efficiency
	HPP =	operating hours per time period (hrs/period)

An emission control efficiency of zero percent applies to all components since the La Goleta facility is not subject to Rule 331 or any District-approved Inspection and Maintenance program for leak detection and repair. The Production Field component specific emission factors from Table 2 of P&P 6100.061 are used to calculate emissions. Detailed emission calculations for fugitive emissions are shown in Attachments 10.1 and 10.2.

4.5 Tanks/Vessels/Separators

4.5.1 *Tanks*: The La Goleta facility operates two flotation cells (brine/hydrocarbon storage tanks), one hydrocarbon liquid storage tank and a brine water storage tank. All four storage tanks are connected to the vapor recovery unit. The detailed tank calculations for the HC condensate tank and the flotation cells will be performed using the methods presented in USEPA AP-42, Chapter 7. Also note that each gas/glycol contactor at the plant is equipped with a pressurized control tank; and the plant operates one NG-blanketed methanol storage tank. All these tank emissions are uncontrolled. However, the emissions are low and are assumed to be less than 0.10 tpy (200 lb/yr.).

4.5.2 *Vessels*: The dehydration facility operates a pressurized odorant storage tank, 1,000 gallons capacity. The pressure vessel is connected to the facility's gas gathering system. All PSVs, vents, and blow down valves vent to the atmosphere. Emissions from a pressure vessel are due to fugitive hydrocarbon leaks from valves and connections. No emission reduction credits are given since the equipment is not subject to District Rule 331.

4.5.3 *Gas/Liquid Separators*: The dehydration facility is equipped with two high-pressure and two low-pressure separators along with a sand trap. Emissions from these separators are due to fugitive hydrocarbon leaks from valves and connections. No emission reduction credits are given since the equipment is not subject to District Rule 331.

4.6 Glycol Reboiler

The glycol reboiler regenerates rich glycol into lean glycol by driving off the water that was picked up during the dehydration of the natural gas. The heat source for this process is the 'oil/glycol heat exchangers' serviced by the 3.500 MMBtu/hr gas-fired hot oil heater and the 2.200 MMBtu/hr gas-fired hot oil heater. Along with water, hydrocarbons are also driven off from the rich glycol. This vapor stream is collected, passed through a condenser and two adsorber beds, and then directed to the flare.

4.7 Other Emission Sources

The following is a brief discussion of other emission sources on La Goleta facility:

4.7.1 *Loading Station*: A grade level loading station is used to load HC condensates from the HC condensate storage tank to trucks. Uncontrolled ROC emissions from the HC condensate loading are 2.76 lb/1,000 gallons of liquid loaded, calculated based on USEPA's AP-42, section 5.2, June 2008. Allowed maximum throughput for the HC condensate is 125,000 gallons/year. The HC/ROC emissions are computed based on this throughput and assuming zero ROC removal efficiency, since the truck loading emissions are not controlled.

4.7.2 *Vapor Recovery System:* Gas from tank farm storage tanks are gathered by a vapor recovery system. Collected gases are piped to the flare for disposal via a blower. A control efficiency of 95 percent is assigned to the system.

4.7.3 *Gas Venting:* Facility Emergency Shut Down (ESD) tests (twice a year) and pipeline operational needs result in occasional depressurizing of pipeline segments at the facility. This is achieved by venting the gases contained in the pipeline segments to the atmosphere through stack vents. Mass emissions from venting are calculated based on the volume of gas vented and the ROC content of the gas.

4.7.4 *Sulfur Removal Unit:* Two pairs of 'Kleen Air' adsorber bed units are used in parallel to remove sulfur compounds from the flash gases given off by the glycol unit. Each pair has an upstream unit with ferric oxide to remove hydrogen sulfide components and a downstream unit with potassium permanganate to remove mercaptans from the waste gas stream. Because they are arranged in parallel, one pair may be taken off-line for maintenance while the other pair treats the waste gas stream. A cumulative sulfur compound removal efficiency is not required; emissions are based on the permitted limit of 239 ppmv.

4.7.5 *General Solvent Cleaning/Degreasing*: Solvent usage (not used as thinners for surface coating) that may occur on La Goleta facility as part of normal daily operations includes a JRI, Model No. TL 21 unit and wipe cleaning. Mass balance emission calculations are used assuming all the solvent used evaporates to the atmosphere (*Section 10.1*).

4.7.5 *Surface Coating*: Surface coating operations typically include normal touch up activities. Entire Plant painting programs may be performed once every few years. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere.

Emission of PM/PM_{10} from paint over spray are not calculated due to the lack of established calculation techniques.

4.7.6 *Abrasive Blasting*: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. Particulate matter is emitted during this process. A general emission factor of 0.01 pound PM per pound of abrasive is used (SCAQMD - Permit Processing Manual, 1989) to estimate emissions of PM and PM_{10} when needed for compliance evaluations. A PM/PM_{10} ratio of 1.0 is assumed.

4.8 BACT/NSPS/NESHAP-MACT

None of the emission units at La Goleta facility are subject to best available control technology (BACT), NSPS, or NESHAPS provisions.

4.9 CEMS/Process Monitoring/CAM

4.9.1 CEMS: There are no CEMS at this facility.

4.9.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the use of process monitoring systems. Examples of these monitors include: gas/liquid flow meters, fuel usage meters, engine hour meters and air-fuel ratio controllers. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors will be required to be calibrated and maintained in good working order:

- Meter(s) recording the flow of gas being processed at the dehydration plant unit 14.
- Gauges recording the volume of HC liquid (condensate) from the hydrocarbon liquid storage tank into trucks at the loading station.
- Meters recording use of natural gas (as fuel) at all IC engines and micro-turbine generators.
- An hour meter at the emergency generator IC engine restricted to 200 hours per year of operation.
- Hour meters at the emergency fire pump engines restricted to 20 hours per year of operation.

To implement the above calibration and maintenance requirements, a *Process Monitor Calibration and Maintenance Plan* is required. This Plan takes into consideration manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment have been utilized.

4.9.3 CAM: SoCalGas La Goleta Plant is a major source that is subject to the USEPA's Compliance Assurance Monitoring (CAM) rule (40 CFR 64). The CAM rule applies to any emissions unit at the facility with an uncontrolled potential to emit exceeding major source emission thresholds for any pollutant (100 tons/year for NOx , ROC, and CO in Santa Barbara County), and which uses control devices to comply with federally enforceable emission standards for these pollutants. Each of the seven (7) spark-ignition, four-stroke rich-burn (4SRB) IC engines at the Plant uses NSCR/AFRC controls to meet the federally enforceable emission standards (NOx, ROC and CO) of District Rule 333, and thus is subject to the CAM Rule. In addition, all the seven engines are subject to more frequent monitoring per the CAM Rule, since the controlled CO potential to emit of each exceeds 100 tons/year (i.e., large pollutant-specific emission units under the CAM Rule). 40 CFR Section 64.3.(b).(4).(ii) sets the guidelines for frequency of monitoring. The District has determined that obtaining one parameter data point per hour is sufficient, since each engine is equipped with alarm sensors controlled by the AFRC millivolt output signal and the thermocouple output signal. Applicable CAM requirements for the engines are listed in Table 4.2 and Condition 9.C.1. This permit revises the allowed AFRC oxygen sensor millivolt set-point range based on historical set-point data for all seven engines. The range represents the bounds for which previous emissions testing has indicated compliance, and the individual ranges for each engine have been eliminated. The CAM plan allows set-points to be changed on any engine provided compliance is demonstrated by emissions data at the new set-point. A QIP will be triggered for any engine if there is a 1% excursion rate of any indicator during a calendar quarter.

4.10 Source Testing/Sampling

Source testing and sampling are required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Table 4.1 details the pollutants, test methods and frequency of required testing. SoCalGas is required to follow the *District Source Test Procedures Manual (May 24, 1990 and all updates)*. The gas compressor engines are the only engines required to be source tested. The micro-turbines may be source tested if portable analyzer measurements indicate an exceedance of emission limits.

The process streams listed in the Table 4.3 are required to be sampled and analyzed. All sampling and analyses are required to be performed according to District approved procedures and methodologies. Typically, the appropriate ASTM methods are acceptable. It is important that all sampling and analysis be traceable by chain of custody procedures. The following table summarizes the sampling requirements:

Table 4.1 IC ENGINE SOURCE TEST REQUIREMENTS[(a)(b)(c)]

SoCalGas ID #	Pollutant or Operation Parameter	Test Methods and Remarks (if any)	Frequency
2 – 8	Exhaust Oxygen, % NOx ppmv, CO ppmv, ROC ppmv[d], NOx lb/hr, CO lb/hr, ROC lb/hr. Catalyst NOx reduction efficiency may be tested as an alternate method of demonstrating compliance with NO_x limits.	Measure: CARB 1-100 for O2; CARB 1-100, or USEPA Method 7E and 10 for NOx and CO respectively; USEPA Method 18 for ROC	Annually
	Engine load, at least 90% of rated horsepower; all source test loads are to be addressed in the Source Test Plans submitted to the District for approval.	Document setting used in testing.	
	The test is to be conducted with AFRC set points at the "as-found" setting		
9	Exhaust Oxygen, % NO_x ppmv, CO ppmv, ROC ppmv[d], NO_x lb/hr, CO lb/hr, ROC lb/hr.	Measure: CARB 1-100 for O_2; CARB 1-100, or USEPA Method 7E and 10 for NO_x and CO respectively; USEPA Method 18 for ROC	Biennially
	Engine load, at least 90% of rated horsepower; all source test loads are to be addressed in the Source Test Plans submitted to the District for approval.	Document setting used in testing.	
	Ignition Timing (°BTDC)		
All engines subject to source testing	Fuel [Ultimate Analysis (HHV, S, H_2S, etc.)]	ASTM Method; Measure	Each Test
All engines subject to source testing	Fuel Flow, scf/hr	METER: Measure at each engine	Each Test

Notes:
a. All emission and process parameter tests shall be performed consistent with District protocol, e.g., all emission tests to consist of a minimum of three 30-minute runs at safe maximum load. USEPA Methods 1-4 to be used to determine O_2, dry MW, moisture content, CO_2 and stack flow rate. Alternately, USEPA 19 may be used to determine stack flow rate. Procedures to obtain the required operating loads shall be defined clearly in the source test plan.
b. All source tested values shall be reported at std. condition (60°F & 14.69 psia), or as otherwise specified.
c. IC engine output (BHP) is determined by RPM.
d. Compliance with the ROC ppmv limit is determined based on the actual concentrations of compounds in the exhaust stream. The concentration should not be reported "as methane" in the source test report.

TABLE 4.2 COMPLIANCE ASSURANCE MONITORING REQUIREMENTS

Indicator	Indicator Range
Oxygen Sensor mV Output	Within 5% of the set point, with the set point between 650 and 875 mV.
Catalyst Inlet Temperature	Greater than 610 deg F
Catalyst Outlet Temperature	Between 610 and 1400 deg F

1. All indicators listed in the table are to be monitored on a '*once per hour*' basis. All monitoring operations shall conform to the requirements of 40 CFR 64.7.(c) [*Continued Operation*].
2. Oxygen sensor millivolt output readings are displayed at each AFRC and sent simultaneously to the SoCalGas operations computer for recording of the same.
3. The temperatures are measured by thermocouples and recorded by the operations computer.

TABLE 4.3 PROCESS STREAM SAMPLING

Process Stream	Parameter (Equipment ID #)	Location	Frequency
Fuel Gas	HHV Total sulfur Hydrogen sulfide Composition	(i) Plant fuel system regulator unit; or (ii) combustion unit inlets	Semi-annually Semi-annually Semi-annually Semi-annually
Vented Gas	ROC Content Total sulfur	Any valve in the storage field piping segment involved	Annually Annually
Hydrocarbon Condensate	API Gravity TVP (RVP)	HC storage tank pump inlet or outlet	Annually Annually
Gaseous Fuel (flare)	HHV # 1211:Total sulfur # 1212:Total Sulfur # 1215:Total sulfur	Gaseous fuel inlet at the flare unit	Annually Semi-annually Semi-annually Annually

TABLE 4.4 - C60 MICRO-TURBINE SOURCE TEST REQUIREMENTS[e, g]					
Emission & Limit Test Points	**Pollutants**	**Parameters[b]**	**Test Methods[a],[c]**	**Concentration Limit**	**Mass Emissions Limit**
				(ppmvd @ 15% O_2)	(lb/hr)
Turbine Exhaust [b]	NO_x	ppmv, lb/hr	EPA Method 7E, ARB 1-100	10	0.03
	ROC	ppmv, lb/hr	EPA Method 18	58	0.06
	CO	ppmv, lb/hr	EPA Method 10, ARB 1-100	199	0.36
	Sampling Point Deter.		EPA Method 1		
	Stack Gas Flow Rate		EPA Method 2 or 19		
	O_2	Dry, Mol. Wt	EPA Method 3		
	Moisture Content		EPA Method 4		
Fuel Gas	Fuel Gas Flow Rate		Fuel Gas Meter[f]		
	Higher Heating Value	BTU/scf	ASTM D 3588-88		
	Total Sulfur Content[d]		EPA 15/16/16A		

Notes:

[a] Alternative methods may be acceptable on a case-by-case basis.
[b] The emission rates shall be based on EPA Methods 2 and 4, or Method 19 along with the heat input rate. Measured NO_x, ROC, and CO ppmvd shall not exceed the limits specified in Condition.9.C.3 (a) of this PTO.

[c] For NO_x, ROC, CO and O_2 a minimum of three 40-minute runs shall be obtained during each test.
[d] Total sulfur content fuel samples shall be obtained using EPA Method 18 with Tedlar Bags (or equivalent) equipped with Teflon tubing and fittings. Turnaround time for laboratory analysis of these samples shall be no more than 24 hours from sampling in the field.
[e] Source testing, when requested by the District, shall be performed for the micro-turbines in an as found condition operating per the District's Source Test Procedures Manual.

[f] Fuel meter shall meet the calibration and metered volume corrections specified in Rule 333, §G.3.a.

[g] Source testing will not be required unless the District specifically requests that the units be tested.

4.11 *Part 70 Engineering Review: Hazardous Air Pollutant Emissions*

The sources of HAP emission factors are listed in Appendix 10.1.

4.11.1 *Natural gas-fired, IC engine with NSCR control:* The HAP emission factors listed in Table 4.7.1 below are used to compute the emissions from the gas-fired, rich-burn, NSCR-controlled IC engines serving the gas compressors.

Table 4.7.1 - HAP Emission Factors		
HAP Species	CAS #	HAP Emission Factor (lb/MMBtu)
Benzene	71-43-2	8.68 E-05
Toluene	108-88-3	4.46 E-05
Acetaldehyde	75-07-0	1.88 E-03
Formaldehyde	50-00-0	3.45 E-04
Acrolein	107-02-8	5.22 E-03

4.11.2 *Natural gas-fired, IC engine with 'Clean Burn' control:* The HAP emission factors listed in Table 4.7.2 below are used to compute the emissions from the single, gas-fired, 'Clean-Burn'-controlled IC engine serving the gas compressor unit #9.

Table 4.7.2 - HAP Emission Factors		
HAP Species	CAS #	HAP Emission Factor (lb/MMBtu)
Benzene	71-43-2	1.17 E-03
Acrolein	107-02-8	4.85 E-03
Acetaldehyde	75-07-0	4.79 E-03
Formaldehyde	50-00-0	5.06 E-02
Methanol	67-56-1	2.49 E-03

4.11.3 *Natural gas-fired, IC engine with no control:* The HAP emission factors listed in Table 4.7.3 below are used to compute the emissions from two gas-fired, 4-stroke, rich-burn, uncontrolled IC engines serving two air compressors.

Table 4.7.3 - HAP Emission Factors		
HAP Species	CAS #	HAP Emission Factor (lb/MMBtu)
Benzene	71-43-2	1.58E-03
Acrolein	107-02-8	2.63 E-03
Acetaldehyde	75-07-0	2.79 E-03
Formaldehyde	50-00-0	2.05 E-02
Methanol	67-56-1	3.06 E-03

4.11.4 *Diesel-fired, IC engine with no control:* The HAP emission factors listed below are for the two diesel-fired engines (i.e., "SCC 2-03-001-01" engines) with no control, driving firewater pumps

Table 4.7.4 - HAP Emission Factors		
HAP Species	CAS #	HAP Emission Factor (lb/MMBtu)
Benzene	71-43-2	9.33E-04
Acrolein	107-02-8	9.25E-05
Acetaldehyde	75-07-0	7.67E-04
Formaldehyde	50-00-0	1.18E-03
Toluene	108-88-3	4.09E-04

4.11.5 *Fugitive VOC Emissions from Piping Components and Seals etc.:* Fugitive HAP emissions listed below occur from components in light liquid/gas service.

Table 4.7.5 - HAP Emission Factors		
HAP Species	CAS #	HAP Weight Fraction (lb/lb ROC)
Benzene	71-43-2	0.0032
Hexane	110-54-3	0.05

4.11.6 *Fugitive VOC Emissions from Waste Water Separators:* Fugitive HAP emissions listed below occur from waste water separators, sumps and cellars.

Table 4.7.5 - HAP Emission Factors		
HAP Species	CAS #	HAP Weight Fraction (lb/lb ROC)
Benzene	71-43-2	0.0271
Hexane	110-54-3	0.0576

5.0 EMISSIONS

5.1 General

Emission calculations are divided into 'permitted' and 'exempt' categories. District permit-exempt equipment is determined by District Rule 202. The permitted emissions for each emissions unit are based on the equipment's potential-to-emit (as defined by Rule 102). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential-to-emit for each emissions unit. Section 5.4 provides the net emissions increase for the facility, if any. Section 5.5 provides the estimated HAP emissions from the La Goleta facility. In order to accurately track the emissions from a facility, the District uses a computer database. Attachment 10.4 contains the District's documentation for the information entered into that database.

5.2 Permitted Emission Limits - Emission Units

Each emissions unit associated with the facility was analyzed to determine the potential-to-emit for the following pollutants:

- ⇒ Nitrogen Oxides (NO_x) [3]
- ⇒ Reactive Organic Compounds (ROC)
- ⇒ Carbon Monoxide (CO)
- ⇒ Sulfur Oxides (SO_x) [4]
- ⇒ Particulate Matter (PM) [5]
- ⇒ Particulate Matter smaller than 10 microns (PM_{10})
- ⇒ Greenhouse Gases (GHG)

Permitted emissions are calculated for both short term (hourly and daily) and long term (quarterly and annual) time periods. Section 4.0 (Engineering Analysis) provides a general discussion of the basic calculation methodologies and emission factors used. The reference documentation for the specific emission calculations, as well as detailed calculation spreadsheets, may be found in Section 4 and Attachments 10.1 and 10.2 respectively. Tables 5.1-1 A/B provide the basic operating characteristics. Tables 5.1-2 A/B provide the specific emission factors. Tables 5.1-3 A/B and 5.1-4 A/B show the permitted short-term and permitted long-term emissions for each unit or operation.

5.3 Permitted Emission Limits - Facility Totals

The total potential-to-emit for all permitted emission units associated with the facility was analyzed. This analysis looked at the reasonable worst-case operating scenarios for each operating period. The equipment operating in each of the scenarios are presented below. Unless otherwise specified, the operating characteristics defined in Table 5.1-1 A/B for each emission unit are assumed. Tables 5.2 A/B show the total permitted emissions for the facility.

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[3] Calculated and reported as nitrogen dioxide (NO_2)

[4] Calculated and reported as sulfur dioxide (SO_2)

[5] Calculated and reported as all particulate matter smaller than 100 μm

Hourly and Daily Scenario:

- All compressor IC engines
- All flares
- Both hot oil heaters
- All well cellars, ROC storage tanks and the condensate loading station
- All fugitive emissions from valves, flanges and other piping components
- Pipeline depressurization venting
- All Micro-turbine generators
- Both Emergency firewater pumps

Quarterly and Annual Scenario:

- All compressor IC engines
- All flares
- Both hot oil heaters
- All well cellars, ROC storage tanks and the condensate loading station
- All fugitive emissions from valves, flanges and other piping components
- Pipeline depressurization venting
- All Micro-turbine generators
- Both Emergency firewater pumps

5.4 Part 70: Federal Potential to Emit for the Facility

Table 5.3 lists the federal Part 70 potential to emit (PTE). Fugitive emissions are excluded from the federal definition of potential to emit unless the source belongs to one of the categories listed in 40 CFR 70.2. This facility does not belong to one of the categories listed in 40 CFR 70.2, therefore fugitive emissions do not contribute to the federal PTE.

This facility does not have the potential to emit 100,000 tpy or more carbon dioxide equivalent emissions. Therefore, the facility is not subject to permitting requirements for greenhouse gas emissions. The emission totals are listed in the permit solely to document the potential to emit of the facility.

5.5 Exempt Emission Sources/Part 70 Insignificant Emissions

Attachment 10.6 lists Equipment/activities exempt from District permits, pursuant to Rule 202.

Insignificant emission units are defined under Part70/District Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. The following emission units are considered insignificant emission units:

- Maintenance Operations involving Solvents (e.g., wipe cleaning)
- Two glycol storage tanks and a glycol run tank;
- Three diesel fuel storage tanks, one 600 gallons and two 110 gallons capacity;
- Three Lube oil storage tanks, 5000 gallons capacity each;
- One 'degreaser' unit (JRI, Model TL 21);
- One glycol/glycol and one glycol/oil heat exchanger; and,
- Emergency backup electrical generator w/ gas-fired IC engine.

Note: Equipment exempt per District Rules may still be considered Part 70 significant units, based on their potential to emit. In this permit, the following units are Part 70 significant units:

- Two 48 bhp Waukesha engines Units # 4A and 5A.

Tables 5.3 A/B showing the federal PTE also present the annual emissions from permit-exempt equipment items, including exempt items considered Part 70 significant. Please note the non-maintenance type solvents or surface coating operations (see Section 9.C) are not permit-exempt.

5.6 Hazardous Air Pollutant Emissions for the Facility

Total emissions of hazardous air pollutants (HAP) are computed based on the emission factors listed in Table 5.4-1 for each emissions unit. Potential HAP emission factors and emissions, based on the worst-case scenario listed in Section 5.6 above, are shown in Tables 5.4-1 A/B and 5.4-2 A/B. The HAP emissions have been included in the Part 70 permit solely for the purpose of any future MACT applicability determination. They do not constitute any emissions or operations limit. More details on HAP emission factors are given in Attachment 10.1 of this permit.

5.7 Net Emissions Increase Calculation

This facility's net emissions increases (NEI) since November 1990, involve the following permit actions and emission increases:

ATC/PTO 8335	(Sept. 93)	ATC 10323	(02/11/02)*
ATC 8946	(06/01/93)	ATC 10324	(06/14/01)*
PTO 8946	(02/09/94)	ATC 10967	(02/26/03)
ATC 9075	(01/11/94)	ATC/PTO 10980	(03/13/03)
PTO 9075	(01/13/95)	PTO 10294	(06/13/03)
ATC 9128	(11/09/93)	ATC 11075	(09/25/03)
PTO 9128	(05/15/95)	PTO 11075	(03/31/04)
ATC 9162	(02/17/94)	ATC 11228	(07/15/04)
PTO 9162	(09/01/94)	PTO 11228	(04/21/05)
ATC/PTO 10016	(06/10/99)*	ATC/PTO 11409	(07/08/05)
ATC 10294	(01/30/01)	ATC 11408	(10/07/05)
ATC 10306	(12/14/01)	PTO 11408	(10/07/05)
		PTO 13479	(05/06/11)

* -- Indicates one or more modifications were issued for this NSR permit.

However, the NEI calculations in this permit are based only on permits issued after April 1997, since earlier data are not available for SoCalGas permits. The NEI equation is given below:

NEI = I + (P1 - P2) – D
Where,

I = potential to emit of the project modifications (*Note: I cannot be negative*);
P1 = all prior emission increases via I terms (at the stationary source) effected by ATCs issued after 11/15/90;

P2 = all decreases (at the stationary source) associated with permits issued after 11/15/90, provided these decreases reflect emissions that were included in previous P1 terms;

D = decreases in actual emissions caused by permit actions at the stationary source, provided these emissions are not included in P2, are not included in the source register or used as a source of emission offsets.

NEI cannot be less than zero, so if an action at the facility reduces the calculated NEI to less than zero, the NEI for the facility is set to zero. For this facility, The NEI decreases for CO are greater than the NEI increases. Therefore the NEI for CO has been set to zero. Per page 8-15 of the Regulation II/VIII Staff Report emission increases are based on the ATC date and emission decreases are based on the PTO date. The NEI for the entire La Goleta facility is shown on the next page.

Table 5.1
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
NEI-90

I. This PTO's "I" (NEI-90)

Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00

II. This Facility's "P1s"
Enter all facility "P1" NEI-90s below:

Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
ATC 9128	Nov' 93	0.00	0.00	21.12	3.85	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC/PTO 10016 02	June '99	0.00	0.00	7.92	1.45	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 10294	Jan '01	0.00	0.00	8.32	1.52	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC Mod 10306 01	Dec '01	0.00	0.00	0.81	0.15	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 10324	June '01	0.00	0.00	3.39	0.62	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 10967	Feb '03	0.00	0.00	2.62	0.48	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC/PTO 10980	March '03	0.00	0.00	0.07	0.10	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 11075	Sep '03	0.00	0.00	1.92	0.35	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 11228	July '04	0.00	0.00	8.60	1.57	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC 11408	June '05	0.00	0.00	8.99	1.64	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC/PTO 11409	July '05	2.88	0.53	7.44	1.36	34.56	6.31	1.05	0.19	0.51	0.09	0.51	0.09
ATC 13479	July '10	0.00	0.00	5.42	0.99	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		**2.88**	**0.53**	**76.62**	**14.08**	**34.56**	**6.31**	**1.05**	**0.19**	**0.51**	**0.09**	**0.51**	**0.09**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

III. This Facility's "P2" NEI-90 Decreases
Enter all facility "P2" NEI-90s below:

Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
None		0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

Notes:
(1) Facility NEI from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

IV. This Facility's Pre-90 "D" Decreases
Enter all facility "D" decreases below:

Permit No.	Date Issued	NOx		ROC		CO		SOx		PM		PM10	
		lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
ATC/PTO 10016 02	June '99	0.00	0.00	15.69	2.87	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTO 10294	June '03	0.00	0.00	23.68	4.32	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTO 11228	April '05	0.00	0.00	14.22	2.60	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
ATC/PTO 11409	July '05	1.11	0.20	7.79	1.42	45.89	8.38	0.02	0.00	0.21	0.04	0.21	0.04
PTO 11408	Oct '05	0.00	0.00	8.02	1.46	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
PTO 13479	May '11	0.00	0.00	3.00	0.55	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Totals		**1.11**	**0.20**	**72.40**	**13.22**	**45.89**	**8.38**	**0.02**	**0.00**	**0.21**	**0.04**	**0.21**	**0.04**

Notes:
(1) Facility "D" from IDS.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.

V. Calculate This Facility's NEI-90
Table below summarizes facility NEI-90 as equal to: I+ (P1-P2) -D

Term	NOx		ROC		CO		SOx		PM		PM10	
	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
PTO "I" (see P1)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P1	2.88	0.53	76.62	14.08	34.56	6.31	1.05	0.19	0.51	0.09	0.51	0.09
P2	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D	1.11	0.20	72.40	13.22	45.89	8.38	0.02	0.00	0.21	0.04	0.21	0.04
FNEI-90	**1.77**	**0.33**	**4.22**	**0.86**	**0.00**	**0.00**	**1.03**	**0.19**	**0.30**	**0.05**	**0.30**	**0.05**

Notes:
(1) Resultant FNEI-90 from above Section I thru IV data.
(2) Totals only apply to permits for this facility ID. Totals may not appear correct due to rounding.
(3) Because of rounding, values in this table shown as 0.00 are less than 0.005, but greater than zero.
(4) CO NEI is set to zero because decreases are greater than increases (NEI cannot be less than zero)

Table 5.1-1 A

SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4

IC Engines Operating Equipment Description

			Device Specifications				Usage Data		Maximum Operating Schedule					
Equipment Category	Description	ID #	Fuel	ppmv S	Size	Units	Capacity	Units	Load	hr	day	qtr	year	References*
Internal Combustion Engines	1199	#2: Ingersoll-Rand LVG-82:	NG	80	650.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	A
- Controlled	1200	#3: Ingersoll-Rand LVG-82:	NG	80	650.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1201	#4: Ingersoll-Rand LVG-82:	NG	80	650.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1202	#5: Ingersoll-Rand LVG-82:	NG	80	650.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1203	#6: Ingersoll-Rand KVG-62:	NG	80	660.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1204	#7: Ingersoll-Rand KVG-62:	NG	80	660.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1205	#8: Ingersoll-Rand KVG-62:	NG	80	660.00	bhp	7.30	MMBtu/hr	1.000	1.0	24	2190	8760	
	1206	#9: Cooper-Bessemer GMV-10C	NG	80	1100.00	bhp	10.02	MMBtu/hr	1.000	1.0	24	2190	8760	
Micro-turbine generators	107543	#1: Capstone C60	NG	80	60	kW	0.804	MMBtu/hr	1.000	1.0	24	2190	8760	
	107544	#2: Capstone C60	NG	80	60	kW	0.804	MMBtu/hr	1.000	1.0	24	2190	8760	B
	107545	#3: Capstone C60	NG	80	60	kW	0.804	MMBtu/hr	1.000	1.0	24	2190	8760	
	107546	#4: Capstone C60	NG	80	60	kW	0.804	MMBtu/hr	1.000	1.0	24	2190	8760	
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	D	15	133	bhp	0.930	MMBtu/hr	1.000	1.0	2	5	20	
	8668	#13A: Cummins V-378-F2	D	15	133	bhp	0.930	MMBtu/hr	1.000	1.0	2	5	20	
Internal Combustion Engines	*1221*	*#4A: Waukesha VRG220U*	NG	80	48.00	bhp	0.50	MMBtu/hr	1.000	1.0	24	2190	8760	I
- Permit exempt but	*1222*	*#5A: Waukesha VRG220U*	NG	80	48.00	bhp	0.50	MMBtu/hr	1.000	1.0	24	2190	8760	
federally significant units														

* -- Refer to Attachment 10.1 for listed References A, B, I

Table 5.1-1 B
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Non-IC Engine Operating Emissions Units Description

			Device Specifications				Usage Data			Maximum Operating Schedule				
Equipment Category	Description	ID #	Fuel	ppmvS	Size	Units	Capacity	Units	Load	hr	day	qtr	year	References*
Combustion - External	Flare: Field	1215	NG	239	--	--	1.600	MMBtu/hr	--	1.0	24	2190	8760	C1
	Flare: Field	1212	NG	239	--	--	1.600	MMBtu/hr	--	1.0	24	2190	8760	
	Flare: Field	1211	NG	239	--	--	1.600	MMBtu/hr	--	1.0	24	2190	8760	
	Hot Oil Heater #1	1214	NG	80	--	--	3.500	MMBtu/hr	--	1.0	24	2190	8760	C2
	Hot Oil Heater #2	107535	NG	80	--	--	2.200	MMBtu/hr	--	1.0	24	2190	8760	
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	--	--	12'd x 12'h	ft	10000.000	gallons	--	1.0	24	2190	8760	D
	Flotation Cell: Tank 2	1220	--	--	12'd x 12'h	ft	10000.000	gallons	--	1.0	24	2190	8760	
	HC Storage Tank	1217	--	--	10'd x 12'h	ft	7050.000	gallons	--	1.0	24	2190	8760	
Loading Station	NGL Loading Station	8669	--	--	--	--	7.140	k-gallons/hour		1.0	3	4	18	E
Fugitive Components	Valves	100882	--	--	2,641	comp.leak-path	--	--	--	1.0	24	2190	8760	G
(Gas/Light Liquid Service)	Connections	100883	--	--	18,339	comp.leak-path	--	--	--	1.0	24	2190	8760	
	Pr. Relief Dev.	100886	--	--	91	comp.leak-path	--	--	--	1.0	24	2190	8760	
	Compressor Seals	100885	--	--	17	comp.leak-path	--	--	--	1.0	24	2190	8760	
	Pump Seals	100884	--	--	2	comp.leak-path	--	--	--	1.0	24	2190	8760	
				clp total:	21,090									
Emissions (Venting)	Wells -- Pipelines	100903	--	--	--	--	10	MMscf/year	--	1.0	24	2190	8760	G
Glycol Unit	Flash-tank Unit	100873	--	--	--	--	680	MMscf/day	--	1.0	24	2190	8760	H
Solvent Usage	Solvent Process Operations	8680	--	--	--	--	0.092	gal/hr (non-photochem)		1.0	6	548	2190	I

Table 5.1-2 A
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
IC Engines Emission Factors

			Emission Factors									
Equipment Category	**Equipment ID**	**Equipment: Plant ID & Description**	**NOx**	**ROC**	**CO**	**SOx**	**PM**	**PM10**	**GHG**	**Units**	**References***
Internal Combustion Engines	1199	#2: Ingersoll-Rand LVG-82:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
- Controlled	1200	#3: Ingersoll-Rand LVG-82:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1201	#4: Ingersoll-Rand LVG-82:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1202	#5: Ingersoll-Rand LVG-82:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1203	#6: Ingersoll-Rand KVG-62:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1204	#7: Ingersoll-Rand KVG-62:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1205	#8: Ingersoll-Rand KVG-62:	0.324	0.321	3.825	0.0129	0.014	0.014	117.00	lb/MMBtu	
	1206	#9: Cooper-Bessemer GMV-10C	0.4600	2.4950	10.125	0.0129	0.0480	0.0480	117.00	lb/MMBtu	
Micro-turbine generators	107543	#1: Capstone C60	0.0373	0.0746	0.448	0.0129	0.0066	0.0066	117.00	lb/MMBtu	
	107544	#2: Capstone C60	0.0373	0.0746	0.448	0.0129	0.0066	0.0066	117.00	lb/MMBtu	
	107545	#3: Capstone C60	0.0373	0.0746	0.448	0.0129	0.0066	0.0066	117.00	lb/MMBtu	
	107546	#4: Capstone C60	0.0373	0.0746	0.448	0.0129	0.0066	0.0066	117.00	lb/MMBtu	
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	14.1	1.12	3.0	0.006	1.0	1.0	163.60	g/bhp-hr	
	8668	#13A: Cummins V-378-F2	14.1	1.12	3.0	0.006	1.0	1.0	163.60	g/bhp-hr	
Internal Combustion Engines	*1221*	*#4A: Waukesha VRG220U*	1.905	0.1030	1.6000	0.0129	0.014	0.014	117.00	lb/MMBtu	
- Permit exempt but	*1222*	*#5A: Waukesha VRG220U*	1.905	0.1030	1.6000	0.0129	0.014	0.014	117.00	lb/MMBtu	
federally significant units											

Table 5.1-2 B
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Non-IC Engine Equipment Emission Factors

			Emission Factors								
Equipment Category	Description		NOx	ROC	CO	SOx	PM	PM10	GHG	Units	References*
Combustion - External	Flare: Field	1215	0.095	0.005	0.082	0.041	0.008	0.008	117.00	lb/MMBtu	C1
	Flare: Field	1212	0.095	0.005	0.082	0.041	0.008	0.008	117.00	lb/MMBtu	
	Flare: Field	1211	0.095	0.005	0.082	0.041	0.008	0.008	117.00	lb/MMBtu	
	Hot Oil Heater #1	1214	0.098	0.005	0.082	0.014	0.008	0.008	117.00	lb/MMBtu	C2
	Hot Oil Heater #2	107535	0.098	0.005	0.082	0.014	0.008	0.008	117.00	lb/MMBtu	
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	--	**Calc's are**	--	--	--	--	--	**AP-42, Ch.7**	D
	Flotation Cell: Tank 2	1220	--	**based on**	--	--	--	--	--	**Eqn. Units --**	
	HC Storage Tank	1217	--	**AP42,Ch.7**	--	--	--	--	--	**multiple para.**	
Loading Station	NGL Loading Station	8669	--	2.7557	--	--	--	--	--	lb/1000 gal	E
Fugitive Components	Valves	100882	--	0.039	--	--	--	--	--	lb/day-clp	G
(Gas/Light Liquid Service)	Connections	100883	--	0.009	--	--	--	--	--	lb/day-clp	
	Pr. Relief Dev.	100886	--	0.887	--	--	--	--	--	lb/day-clp	
	Compressor Seals	100885	--	0.285	--	--	--	--	--	lb/day-clp	
	Pump Seals	100884	--	0.149	--	--	--	--	--	lb/day-clp	
Emissions (Venting)	Wells -- Pipelines	100903	--	6789	--	--	--	--	657121.00	lb/MMscf	G
Glycol Unit	Flash-tank Unit	100873	--	**Gly-Calc 4.0**	--	--	--	--	--		
Solvent Usage	Solvent Process Operations	8680	--	4.000	--	--	--	--	--	lbs./gal	H

* -- Please refer to Attachment 10.1 for References C - H

Table 5.1-3 A

SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4

IC Engines Short-Term Permitted Emissions

			Mass Emission Limits													
			NOx		ROC		CO		SOx		PM		PM10		GHG	
Equipment Category	**Equipment ID**	**Equipment: Plant ID & Description**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**	**lb/hr**	**lb/day**
Internal Combustion Engines	1199	#2: Ingersoll-Rand LVG-82:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
- Controlled	1200	#3: Ingersoll-Rand LVG-82:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1201	#4: Ingersoll-Rand LVG-82:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1202	#5: Ingersoll-Rand LVG-82:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1203	#6: Ingersoll-Rand KVG-62:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1204	#7: Ingersoll-Rand KVG-62:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1205	#8: Ingersoll-Rand KVG-62:	2.37	56.76	2.34	56.24	27.92	670.14	0.09	2.26	0.10	2.45	0.10	2.45	854.10	20498.40
	1206	#9: Cooper-Bessemer GMV-10C	4.61	110.62	25.00	600.00	101.45	2434.86	0.13	3.10	0.48	11.54	0.48	11.54	1172.34	28136.16
															0.00	0.00
Micro-turbine generators	107543	#1: Capstone C60	0.03	0.72	0.06	1.44	0.36	8.64	0.01	0.25	0.01	0.13	0.01	0.13	94.07	2257.63
	107544	#2: Capstone C60	0.03	0.72	0.06	1.44	0.36	8.64	0.01	0.25	0.01	0.13	0.01	0.13	94.07	2257.63
	107545	#3: Capstone C60	0.03	0.72	0.06	1.44	0.36	8.64	0.01	0.25	0.01	0.13	0.01	0.13	94.07	2257.63
	107546	#4: Capstone C60	0.03	0.72	0.06	1.44	0.36	8.64	0.01	0.25	0.01	0.13	0.01	0.13	94.07	2257.63
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	4.12	8.25	0.33	0.66	0.89	1.78	0.00	0.00	0.29	0.58	0.29	0.58	152.15	304.30
	8668	#13A: Cummins V-378-F2	4.12	8.25	0.33	0.66	0.89	1.78	0.00	0.00	0.29	0.58	0.29	0.58	152.15	304.30
Total for Permitted Engines			**29.54**	**527.35**	**42.30**	**1000.74**	**300.13**	**7163.97**	**0.83**	**19.89**	**1.80**	**30.38**	**1.80**	**30.38**	**7831.61**	**181264.08**
Internal Combustion Engines	*1221*	*#4A: Waukesha VRG220U*	*0.95*	*22.86*	*0.05*	*1.24*	*0.80*	*19.20*	*0.01*	*0.15*	*0.01*	*0.17*	*0.01*	*0.17*	58.50	1404.00
- Permit exempt but	*1222*	*#5A: Waukesha VRG220U*	*0.95*	*22.86*	*0.05*	*1.24*	*0.80*	*19.20*	*0.01*	*0.15*	*0.01*	*0.17*	*0.01*	*0.17*	58.50	1404.00
federally significant units																
Total for permit exempt engines			***1.91***	***45.72***	***0.10***	***2.47***	***1.60***	***38.40***	***0.01***	***0.31***	***0.01***	***0.34***	***0.01***	***0.34***	***117.00***	***2808.00***

Table 5.1-3 B
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Non-IC Engines Daily Emissions

Equipment Category	Description		NOx lb/day	ROC lb/day	CO lb/day	SOx lb/day	PM lb/day	PM10 lb/day	GHG lb/day
Combustion - External	Flare: Field	1215	3.66	0.20	3.16	1.57	0.29	0.29	4493
	Flare: Field	1212	3.66	0.20	3.16	1.57	0.29	0.29	4493
	Flare: Field	1211	3.66	0.20	3.16	1.57	0.29	0.29	4493
	Hot Oil Heater #1	1214	8.23	0.45	6.89	1.15	0.63	0.63	9828
	Hot Oil Heater #2	107535	5.17	0.29	4.33	0.72	0.40	0.40	6178
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	--	0.21	--	--	--	--	--
	Flotation Cell: Tank 2	1220	--	0.21	--	--	--	--	--
	HC Storage Tank	1217		0.19					
Loading Station	NGL Loading Station	8669	--	55.09	--	--	--	--	--
Fugitive Components	Valves	100882	--	103.62	--	--	--	--	--
(Gas/Light Liquid Service)	Connections	100883	--	170.74	--	--	--	--	--
	Pr. Relief Dev.	100886	--	80.73	--	--	--	--	--
	Compressor Seals	100885	--	4.85	--	--	--	--	--
	Pump Seals	100884	--	0.30	--	--	--	--	--
Emissions (Venting)	Wells -- Pipelines	100903	--	186.00	--	--	--	--	18003
Glycol Unit	Flash-tank Unit	100873	--	52.13	--	--	--	--	--
Solvent Usage**	Solvent Process Operations	8680	--	2.21	--	--	--	--	--

** -- This item does not represent an emissions limit

Table 5.1-4 A

SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4

IC Engines Long-Term Permitted Emissions

			Mass Emission Limits													
			NOx		ROC		CO		SOx		PM		PM10		GHG	
Equipment Category	Equipment ID	Equipment: Plant ID & Description	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY
Internal Combustion Engines	1199	#2: Ingersoll-Rand LVG-82:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
- Controlled	1200	#3: Ingersoll-Rand LVG-82:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1201	#4: Ingersoll-Rand LVG-82:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1202	#5: Ingersoll-Rand LVG-82:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1203	#6: Ingersoll-Rand KVG-62:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1204	#7: Ingersoll-Rand KVG-62:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1205	#8: Ingersoll-Rand KVG-62:	2.59	10.36	2.57	10.26	30.58	122.30	0.10	0.41	0.11	0.45	0.11	0.45	935.24	3740.96
	1206	#9: Cooper-Bessemer GMV-10C	5.05	20.19	27.37	109.50	111.09	444.36	0.14	0.57	0.53	2.11	0.53	2.11	1283.71	5134.85
Micro-turbine generators	107543	#1: Capstone C60	0.03	0.13	0.07	0.26	0.39	1.58	0.01	0.05	0.01	0.02	0.01	0.02	103.00	412.02
	107544	#2: Capstone C60	0.03	0.13	0.07	0.26	0.39	1.58	0.01	0.05	0.01	0.02	0.01	0.02	103.00	412.02
	107545	#3: Capstone C60	0.03	0.13	0.07	0.26	0.39	1.58	0.01	0.05	0.01	0.02	0.01	0.02	103.00	412.02
	107546	#4: Capstone C60	0.03	0.13	0.07	0.26	0.39	1.58	0.01	0.05	0.01	0.02	0.01	0.02	103.00	412.02
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	0.01	0.04	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.38	1.52
	8668	#13A: Cummins V-378-F2	0.01	0.04	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.00	0.01	0.38	1.52
Total for Permitted Engines			**23.33**	**93.31**	**45.60**	**182.42**	**326.70**	**1306.80**	**0.91**	**3.65**	**1.34**	**5.35**	**1.34**	**5.35**	**8243.17**	**32972.67**
Internal Combustion Engines	*1221*	*#4A: Waukesha VRG220U*	*1.04*	*4.17*	*0.06*	*0.23*	*0.88*	*3.50*	*0.01*	*0.03*	*0.01*	*0.03*	*0.01*	*0.03*	64.06	256.23
- Permit exempt but	*1222*	*#5A: Waukesha VRG220U*	*1.04*	*4.17*	*0.06*	*0.23*	*0.88*	*3.50*	*0.01*	*0.03*	*0.01*	*0.03*	*0.01*	*0.03*	64.06	256.23
federally significant units																
Total for permit exempt engines			*2.09*	*8.34*	*0.11*	*0.45*	*1.75*	*7.01*	*0.01*	*0.06*	*0.02*	*0.06*	*0.02*	*0.06*	*128.12*	*512.46*

Table 5.1-4 B
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Non-IC Engines Annual Emissions

Equipment Category	Description		NOx TPY	ROC TPY	CO TPY	SOx TPY	PM TPY	PM10 TPY	GHG TPY
Combustion - External	Flare: Field	1215	0.67	0.04	0.58	0.29	0.05	0.05	819.94
	Flare: Field	1212	0.67	0.04	0.58	0.29	0.05	0.05	819.94
	Flare: Field	1211	0.67	0.04	0.58	0.29	0.05	0.05	819.94
	Hot Oil Heater #1	1214	1.50	0.08	1.26	0.21	0.11	0.11	1793.61
	Hot Oil Heater #2	107535	0.94	0.05	0.79	0.13	0.07	0.07	1127.41
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	--	0.04	--	--	--	--	--
	Flotation Cell: Tank 2	1220	--	0.04	--	--	--	--	--
	HC Storage Tank	1217		0.03					
Loading Station	NGL Loading Station	8669	--	0.17	--	--	--	--	--
Fugitive Components (Gas/Light Liquid Service)	Valves	100882	--	18.91	--	--	--	--	--
	Connections	100883	--	31.16	--	--	--	--	--
	Pr. Relief Dev.	100886	--	14.73	--	--	--	--	--
	Compressor Seals	100885	--	0.88	--	--	--	--	--
	Pump Seals	100884	--	0.05	--	--	--	--	--
Emissions (Venting)	Wells -- Pipelines	100903	--	33.95	--	--	--	--	3285.61
Glycol Unit	Flash-tank Unit	100873	--	9.51	--	--	--	--	--
Solvent Usage**	Solvent Process Operations	8680	--	0.40	--	--	--	--	--

** -- This item does not represent an emissions limit

Table 5.2
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Facility Permitted Potential to Emit (FPTE)

A. DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion -- IC Engines	527.35	1,000.74	7,163.97	19.89	30.38	30.38	181264.08
Combustion - External	24.37	1.33	20.71	6.60	1.89	1.89	29484.00
HC Liquid Storage Tanks	--	0.61	--	--	--	--	--
Loading Station	--	55.09	--	--	--	--	--
Fugitive Components (Gas/LL Service)	--	360.23	--	--	--	--	--
Emissions (Venting)	--	186.00	--	--	--	--	18003
Glycol unit	--	52.13	--	--	--	--	--
Solvent Usage**	--	2.21	--	--	--	--	--
TOTAL:	551.73	1,658.33	7,184.68	26.49	32.27	32.27	228,751.40

B. ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion -- IC Engines	93.31	182.42	1,306.80	3.65	5.35	5.35	32,972.67
Combustion - External	4.45	0.24	3.78	1.20	0.34	0.34	5,380.83
HC Liquid Storage Tanks	--	0.11	--	--	--	--	--
Loading Station	--	0.17	--	--	--	--	--
Fugitive Components (Gas/LL Service)	--	65.74	--	--	--	--	--
Emissions (Venting)	--	33.95	--	--	--	--	3286
Glycol unit	--	9.51	--	--	--	--	--
Solvent Usage**	--	0.40	--	--	--	--	--
TOTAL:	97.76	292.54	1,310.58	4.85	5.70	5.70	41,639.10

** -- This item does not represent an emissions limit

Table 5.3
SoCalGas LaGoleta Plant: PT-70/Reeval 9584-R4
Facility Federal Potential to Emit (PTE-Fed)

A. DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion -- IC engines	573.07	1,003.21	7,202.37	20.20	30.72	30.72	184,072.08
Combustion - external	24.37	1.33	20.71	6.60	1.89	1.89	29,484.00
HC Liquid Storage Tanks	--	0.61	--	--	--	--	--
Loading Station	--	55.09	--	--	--	--	--
Fugitive Components (Gas/LL Service)	--	0.00	--	--	--	--	--
Emissions (Venting)	--	186.00	--	--	--	--	18,003.32
Glycol unit	--	52.13	--	--	--	--	--
Solvent Usage**	--	2.21	--	--	--	--	--
TOTAL:	597.45	1,300.58	7,223.08	26.80	32.61	32.61	231,559.40

B. ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10	GHG
Combustion -- IC engines	101.66	182.87	1,313.80	3.70	5.41	5.41	33,485.13
Combustion - External	4.45	0.24	3.78	1.20	0.34	0.34	5,380.83
HC Liquid Storage Tanks	--	0.11	--	--	--	--	--
Loading Station	--	0.17	--	--	--	--	--
Fugitive Components (Gas/LL Service)	--	0.00	--	--	--	--	--
Emissions (Venting)	--	33.95	--	--	--	--	3,285.61
Glycol unit	--	9.51	--	--	--	--	—
Solvent Usage**	--	0.40	--	--	--	--	—
TOTAL:	106.11	227.25	1,317.58	4.91	5.76	5.76	42,151.56

Table 5.4-1 A
SoCalGas La Goleta Plant: Part 70/APCD PTO 9584-R3
IC Engines' HAP Emission Factors

Equipment Category	Equipment ID	Equipment: Plant ID	Emission Factors Benzene	Acrolein	Acetaldehyde	Formaldehyde	Methanol	Naphthalene	Toluene	Units
Internal Combustion Engines	1199	#2: Ingersoll-Rand LVG-82:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
- Controlled	1200	#3: Ingersoll-Rand LVG-82:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1201	#4: Ingersoll-Rand LVG-82:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1202	#5: Ingersoll-Rand LVG-82:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1203	#6: Ingersoll-Rand KVG-62:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1204	#7: Ingersoll-Rand KVG-62:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1205	#8: Ingersoll-Rand KVG-62:	8.68E-05	5.22E-03	1.88E-03	3.45E-04	2.32E-03	3.39E-05	4.46E-05	lb/MMBtu
	1209	#9: Cooper-Bessemer GMV-10C	1.17E-03	4.85E-03	4.79E-03	5.06E-02	2.49E-03	1.17E-04	1.05E-03	lb/MMBtu
Micro-turbine generators	107543	#1: Capstone C60	1.20E-05	6.40E-06	4.00E-05	7.10E-04	0.00E+00	3.50E-05	1.30E-04	lb/MMBtu
	107544	#2: Capstone C60	1.20E-05	6.40E-06	4.00E-05	7.10E-04	0.00E+00	3.50E-05	1.30E-04	lb/MMBtu
	107545	#3: Capstone C60	1.20E-05	6.40E-06	4.00E-05	7.10E-04	0.00E+00	3.50E-05	1.30E-04	lb/MMBtu
	107546	#4: Capstone C60	1.20E-05	6.40E-06	4.00E-05	7.10E-04	0.00E+00	3.50E-05	1.30E-04	lb/MMBtu
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	9.33E-04	9.25E-05	7.67E-04	1.18E-03	0.00E+00	8.48E-05	4.09E-04	lb/MMBtu
	8668	#13A: Cummins V-378-F2	9.33E-04	9.25E-05	7.67E-04	1.18E-03	0.00E+00	8.48E-05	4.09E-04	lb/MMBtu
Internal Combustion Engines	*1221*	*#4A: Waukesha VRG220U*	1.58E-03	2.63E-03	2.79E-03	2.05E-02	3.06E-03	9.71E-05	5.58E-04	lb/MMBtu
- Permit exempt but federally significant units	*1222*	*#5A: Waukesha VRG220U*	1.58E-03	2.63E-03	2.79E-03	2.05E-02	3.06E-03	9.71E-05	5.58E-04	lb/MMBtu

Table 5.4-1B
SoCalGas LaGoleta Plant -- Part 70/APCD PTO 9584-R3
Non-ICE Equipment HAP Emission Factors

Facility ID #: 01734

Equipment Category	Emissions Unit	ID #	ROC	Emission Factors Formaldehyde	Hexane	Acetaldehyde	Benzene	Toluene	Units
Combustion - External	Flare: Field	1215	1.000	0.0171	0.0000	0.0071	0.0812	0.0336	weight fraction
	Flare: Field	1212	1.000	0.0171	0.0000	0.0071	0.0812	0.0336	weight fraction
	Flare: Field	1211	1.000	0.0171	0.0000	0.0071	0.0812	0.0336	weight fraction
	Hot Oil Heater #1	1214	0.005	7.35E-05	1.76E-03	0.00E+00	2.06E-06	3.33E-06	lb/MMBtu
	Hot Oil Heater #2	107535	0.005	7.35E-05	1.76E-03	0.00E+00	2.06E-06	3.33E-06	lb/MMBtu
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	0.1150	-	0.0576	-	0.0271	-	weight fraction
	Flotation Cell: Tank 2	1220	0.1150	-	0.0576	-	0.0271	-	weight fraction
	HC Storage Tank	1217	0.1150	-	0.0576	-	0.0271	-	weight fraction
Loading Station	NGL Loading Station	8669	0.4400	-	0.1768	-	0.0018	-	weight fraction
Fugitive Components	Valves	100882	0.6920	-	0.0500	-	0.0032	-	weight fraction
(Gas/Light Liquid Service)	Connections	100883	0.6920	-	0.0500	-	0.0032	-	weight fraction
	Press. Relief Dev.(acces)	100886	0.6920	-	0.0500	-	0.0032	-	weight fraction
	Compressor Seals	100885	0.6920	-	0.0500	-	0.0032	-	weight fraction
	Pump Seals	100884	0.6920	-	0.0500	-	0.0032	-	weight fraction
Emissions (Venting)	Wells -- Pipelines	100903	0.6920	-	0.0500	-	0.0032	-	weight fraction
Glycol Unit	Flash-tank Unit	100873	Gly-Calc 4.(	-	-	-	-	-	

Table 5.4-2 A
SoCalGas La Goleta Plant: Part 70/APCD PTO 9584-R3
IC Engines' HAP Emission (Potential to Emit)

Equipment Category	Equipment I	Equipment: Plant ID	Benzene	Acrolein	Acetaldehyde	Formaldehyde	Methanol	Naphthalene	Toluene
			Emissions (tons/year)						
Internal Combustion Engines - *Controlled*	1199	#2: Ingersoll-Rand LVG-82:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1200	#3: Ingersoll-Rand LVG-82:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1201	#4: Ingersoll-Rand LVG-82:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1202	#5: Ingersoll-Rand LVG-82:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1203	#6: Ingersoll-Rand KVG-62:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1204	#7: Ingersoll-Rand KVG-62:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1205	#8: Ingersoll-Rand KVG-62:	2.78E-03	1.67E-01	6.01E-02	1.10E-02	7.42E-02	1.08E-03	1.43E-03
	1209	#9: Cooper-Bessemer GMV-1(	5.13E-02	2.13E-01	2.10E-01	2.22E+00	1.09E-01	5.13E-03	4.61E-02
Micro-turbine generators	107543	#1: Capstone C60	4.23E-05	2.25E-05	1.41E-04	2.50E-03	0.00E+00	4.58E-04	4.58E-04
	107544	#2: Capstone C60	4.23E-05	2.25E-05	1.41E-04	2.50E-03	0.00E+00	4.58E-04	4.58E-04
	107545	#3: Capstone C60	4.23E-05	2.25E-05	1.41E-04	2.50E-03	0.00E+00	4.58E-04	4.58E-04
	107546	#4: Capstone C60	4.23E-05	2.25E-05	1.41E-04	2.50E-03	0.00E+00	4.58E-04	4.58E-04
Emergency Fire Pumps	8666	#12A: Cummins V-378-F2	8.68E-06	8.60E-07	7.13E-06	1.10E-05	0.00E+00	7.89E-07	3.80E-06
	8668	#13A: Cummins V-378-F2	8.68E-06	8.60E-07	7.13E-06	1.10E-05	0.00E+00	7.89E-07	3.80E-06
Internal Combustion Engines - *Emissions not Controlled*	*1221*	*#4A: Waukesha VRG220U*	*3.46E-03*	*5.76E-03*	*6.11E-03*	*4.49E-02*	*6.70E-03*	*2.13E-04*	1.22E-03
	1222	*#5A: Waukesha VRG220U*	*3.46E-03*	*5.76E-03*	*6.11E-03*	*4.49E-02*	*6.70E-03*	*2.13E-04*	1.22E-03
		TOTAL HAPS =	**0.08**	**1.39**	**0.64**	**2.40**	**0.64**	**0.01**	**0.06**

Table 5.4-2 B

SoCalGas LaGoleta Plant -- Part 70/APCD PTO 9584-R3

Non-IC Engines' Hourly and Daily HAP Emissions

Facility ID #: 01734

Equipment Category	Emissions Unit	ID #	ROC lbs/hr	ROC lbs/day	Formaldehyde lbs/hr	Formaldehyde lbs/day	Hexane lbs/hr	Hexane lbs/day	Acetaldehyde lbs/hr	Acetaldehyde lbs/day	Benzene lbs/hr	Benzene lbs/day	Toluene lbs/hr	Toluene lbs/day
Combustion - External	Flare: Field	1215	0.01	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.01
	Flare: Field	1212	0.01	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.01
	Flare: Field	1211	0.01	0.20	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.02	0.00	0.01
	Hot Oil Heater #1	1214	0.02	0.45	0.00	0.01	0.01	0.15	0.00	0.00	0.00	0.00	0.00	0.00
	Hot Oil Heater #2	107535	0.01	0.29	0.00	0.00	0.00	0.09	0.00	0.00	0.00	0.00	0.00	0.00
HC Liquid Storage Tank:	Flotation Cell: Tank 1	1219	0.01	0.21	-	-	0.00	0.01	-	-	0.00	0.01	-	-
	Flotation Cell: Tank 2	1220	0.01	0.21	-	-	0.00	0.01	-	-	0.00	0.01	-	-
	HC Storage Tank	1217	0.01	0.19	-	-	0.00	0.01	-	-	0.00	0.01	-	-
Loading Station	NGL Loading Station	8669	19.68	55.09	-	-	3.48	9.74	-	-	0.04	0.10	-	-
Fugitive Components	Valves	100882	4.31	103.50	-	-	0.22	5.18	-	-	0.01	0.34	-	-
(Gas/Light Liquid Servic	Connections	100883	7.10	170.40	-	-	0.36	8.52	-	-	0.02	0.55	-	-
	Press. Relief Dev.(open)	100886	3.29	78.95	-	-	0.16	3.95	-	-	0.01	0.26	-	-
	Compressor Seals	100885	0.20	4.85	-	-	0.01	0.24	-	-	0.00	0.02	-	-
	Pump Seals	100884	0.01	0.30	-	-	0.00	0.01	-	-	0.00	0.00	-	-
Emissions (Venting)	Wells -- Pipelines	100903	7.75	186.00	-	-	0.39	9.30	-	-	0.03	0.60	-	-
Glycol Unit	Flash Tank Unit	100873	2.17	52.13	-	-	0.21	5.11	-	-	0.11	2.70		
		TOTAL:	**44.59**	**653.16**	**0.00**	**0.02**	**4.83**	**42.33**	**0.00**	**0.00**	**0.22**	**4.63**	**0.00**	**0.02**

Table 5.4-2 C

SoCalGas LaGoleta Plant -- Part 70/APCD PTO 9584-R3

Non-IC Engines' Quarterly and Annual HAP Emissions

Facility ID #: 01734

Equipment Category	Emissions Unit	ID #	ROC TPQ	ROC TPY	Formaldehyde TPQ	Formaldehyde TPY	Hexane TPQ	Hexane TPY	Acetaldehyde TPQ	Acetaldehyde TPY	Benzene TPQ	Benzene TPY	Toluene TPQ	Toluene TPY
Combustion - External	Flare: Field	1215	0.01	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Flare: Field	1212	0.01	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Flare: Field	1211	0.01	0.04	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
	Hot Oil Heater #1	1214	0.02	0.08	0.00	0.00	0.01	0.03	0.00	0.00	0.00	0.00	0.00	0.00
	Hot Oil Heater #2	107535	0.01	0.05	0.00	0.00	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00
HC Liquid Storage Tanks	Flotation Cell: Tank 1	1219	0.01	0.04	-	-	0.00	0.00	-	-	0.00	0.00	-	-
	Flotation Cell: Tank 2	1220	0.01	0.04	-	-	0.00	0.00	-	-	0.00	0.00	-	-
	HC Storage Tank	1217	0.01	0.03	-	-	0.00	0.00	-	-	0.00	0.00	-	-
Loading Station	NGL Loading Station	8669	0.04	0.17	-	-	0.01	0.03	-	-	0.00	0.00	-	-
Fugitive Components (Gas/Light Liquid Service)	Valves	100882	4.72	18.89	-	-	0.24	0.94	-	-	0.02	0.06	-	-
	Connections	100883	7.77	31.10	-	-	0.39	1.55	-	-	0.03	0.10	-	-
	Press. Relief Dev.(acces)	100886	3.60	14.41	-	-	0.18	0.72	-	-	0.01	0.05	-	-
	Compressor Seals	100885	0.22	0.88	-	-	0.01	0.04	-	-	0.00	0.00	-	-
	Pump Seals	100884	0.01	0.05	-	-	0.00	0.00	-	-	0.00	0.00	-	-
Emissions (Venting)	Wells -- Pipelines	100903	8.49	33.95	-	-	0.42	1.70	-	-	0.03	0.11	-	-
Glycol Unit	Flash-tank Unit	100873	2.38	9.51	-	-	0.23	0.93	-	-	0.12	0.49	-	-
			27.33	109.31	0.00	0.00	1.49	5.97	0.00	0.00	0.21	0.82	0.00	0.00

Table 5.4-3

SoCalGas LaGoleta Plant -- Part 70/APCD PTO 9584-R3

Total Estimated HAP Emissions for the Facility

Facility ID #: 01734

Peak Daily (lb/day)

Equipment Category	ROC	Formaldehyde	Hexane	Acetaldehyde	Benzene	Toluene	Acrolein	Methanol	Naphthalene
Combustion - ICEs	632.57								
Combustion - External	1.33	0.02	0.24	0.00	0.05	0.02	0.00	0.00	0.00
HC Liq.Storage Tank	0.61	0.00	0.04	0.00	0.02	0.00	0.00	0.00	0.00
NGL Loading Station	55.09	0.00	9.74	0.00	0.10	0.00	0.00	0.00	0.00
Fug.Comp. - - Gas/LL	358.00	0.00	17.90	0.00	1.16	0.00	0.00	0.00	0.00
Well Venting	186.00	0.00	9.30	0.00	0.60	0.00	0.00	0.00	0.00
Glycol Unit	52.13	0.00	5.11	0.00	2.70	0.00	0.00	0.00	0.00
TOTALS (lb/day)	**1,285.72**	**0.02**	**42.33**	**0.00**	**4.63**	**0.02**	**0.00**	**0.00**	**0.00**

Peak Annual (Ton/yr)

Equipment Category	ROC	Formaldehyde	Hexane	Acetaldehyde	Benzene	Toluene	Acrolein	Methanol	Naphthalene
Combustion - ICEs	115.22	2.40	0.00	0.64	0.08	0.06	1.39	0.64	0.01
Combustion - External	0.24	0.00	0.04	0.00	0.01	0.00	0.00	0.00	0.00
HC Liq.Storage Tank	0.11	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00
NGL Loading Station	0.17	0.00	0.03	0.00	0.00	-	0.00	0.00	0.00
Fug.Comp. - - Gas/LL	65.33	0.00	3.27	0.00	0.21	0.00	0.00	0.00	0.00
Well Venting	33.95	0.00	1.70	0.00	0.11	0.00	0.00	0.00	0.00
Glycol Unit	9.51	0.00	0.93	0.00	0.49	0.00	0.00	0.00	0.00
TOTALS (ton/yr)	**224.54**	**2.40**	**5.97**	**0.64**	**0.90**	**0.06**	**1.39**	**0.64**	**0.01**

6.0 Air Quality Impact Analyses

6.1 *Modeling*

Air quality modeling was not required for this stationary source.

6.2 *Increments*

An air quality increment analysis was not required for this stationary source

6.3 *Monitoring*

Air quality monitoring is not required for this stationary source.

6.4 *Health Risk Assessment*

The SoCalGas La Goleta stationary source is subject to the Air Toxics Hot-Spots Program (AB-2588). A health risk assessment (HRA) for the facility was prepared by the District on May 22, 1996 under the requirements of the Air Toxics "Hot Spots" Information and Assessment Act of 1987 (AB 2588). The HRA is based on 1994 toxic emissions inventory data submitted to the District by SoCalGas.

Based on the 1994 toxic emissions inventory, a cancer risk of 7 per million off the property was estimated for the La Goleta facility. This risk is primarily due to emissions of polycyclic aromatic hydrocarbon (PAH) from internal combustion devices (generators, cranes, heaters, compressors, etc.). Additionally, a chronic risk of 0.10 has been estimated by the District and is mainly due to acrolein emissions for internal combustion devices. The cancer and non-cancer chronic risk projections are well below the District's AB-2588 significance thresholds of 10 in a million and 1.0 in a million, respectively.

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 *General*

The stationary source is located in an ozone nonattainment area. Santa Barbara County has not attained the state ozone ambient air quality standards. The County also does not meet the state PM_{10} ambient air quality standards. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with progress toward attainment of federal and state ambient air quality standards. Under District regulations, any modifications at the source that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Increases above offset thresholds will trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM_{10}, for which the level is 80 lbs/day.

7.2 *Clean Air Plan*

The 2007 Clean Air Plan, adopted by the District Board on August 16, 2007, addressed both federal and state requirements, serving as the maintenance plan for the federal eight-hour ozone standard and as the state triennial update required by the Health and Safety Code to demonstrate how the District will expedite attainment of the state eight-hour ozone standard.

The plan was developed for Santa Barbara County as required by both the 1998 California Clean Air Act and the 1990 Federal Clean Air Act Amendments.

On January 20, 2011 the District Board adopted the 2010 Clean Air Plan. The 2010 Plan provides a three-year update to the 2007 Clean Air Plan. As Santa Barbara County has yet to attain the state eight-hour ozone standard, the 2010 Clean Air Plan demonstrates how the District plans to attain that standard. The 2010 Clean Air Plan therefore satisfies all state triennial planning requirements.

7.3 *Offset Requirements*

SoCalGas La Goleta stationary source does not currently require emission offsets to operate.

7.4 *Emission Reduction Credits*

The SoCalGas La Goleta stationary source generates and provides NO_x emission reduction credits to the Point Arguello Project, as follows:

> Seven compressor engines, units #2 - #8, provide the emission reduction credits. Each of the seven engines is equipped with a NO_x abatement system. The system consists of a non-selective catalytic converter aided by an automatic air-fuel-ratio controller. The NO_x control provides a minimum NO_x emission reduction of 90 percent.

Estimated minimum reductions:

The expected minimum NO_x emission reduction for each engine, based on PTO 7500, was estimated as follows:

> Uncontrolled NO_x emissions from each engine = 3400 lb/MMscf = 3.238 lb/MMBtu;
> Minimum emissions reduction from each engine = 0.9 * 3.238 = 2.914 lb/MMBtu;
> Anticipated average heat input/engine (minimum annual fuel data) = 3.19 MMBtu/hour;
> Expected minimum NO_x emission reductions/engine = 2.914 * 3.19 = 9.296 lb/hr.
> *Expected NO_x emission reductions from the Plant = 7 * 9.296*8760/2000 = 285 tons/yr.*

Out of the total annual NO_x emissions reduction of 285 tons expected to be achieved at the La Goleta Plant, 96.06 tons are currently allotted to the Point Arguello Project (i.e., the Outer Continental Shelf components only of the Project).

The emission reduction credits offered by the La Goleta source are verified through quarterly recording and reporting of quantities of emissions captured. Annual source tests are the mechanisms for verifying the emission reduction credits achieved. Operational compliance to ensure ERCs is also verified through on-site inspections. The operating requirements to ensure these emission reductions are stipulated in Section 9.C.1 of this permit.

8.0 Lead Agency Permit Consistency

To the best of the District's knowledge, no other government agency's permit requires air quality mitigation for emissions pursuant to this District reevaluation permit 9584-R4 issued for the SoCalGas La Goleta stationary source.

9.0 Permit Conditions

This section lists the applicable permit conditions for the La Goleta Gas Plant. Section A lists the standard administrative conditions. Section B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section C lists conditions affecting specific equipment. Section D lists non-federally enforceable (i.e., District only) permit conditions. Conditions listed in Sections A, B and C are enforceable by the USEPA, the District, the State of California and the public. Conditions listed in Section D are enforceable only by the District and the State of California. Where any reference contained in Sections 9.A, 9.B, and 9.C refers to any other part of this permit that part of the permit referred to is federally enforceable. In case of a discrepancy between the wording of a condition and the applicable federal or District rule(s), the wording of the rule(s) shall control.

For the purposes of submitting compliance certifications or establishing whether or not a person has violated or is in violation of any standard in this permit, nothing in the permit shall preclude the use, including the exclusive use, of any credible evidence or information, relevant to whether a source would have been in compliance with applicable requirements if the appropriate performance or compliance test had been performed.

9.A Standard Administrative Conditions

The following administrative permit conditions apply to La Goleta facility:

A.1 Compliance with Permit Conditions.

(a) The permittee shall comply with all permit conditions in Sections 9.A, 9.B and 9.C.

(b) This permit does not convey property rights or exclusive privilege of any sort.

(c) Noncompliance with any permit conditions is grounds for permit termination, revocation and re-issuance, modification, enforcement action, or for denial of permit renewal. Any permit non-compliance constitutes a violation of the Clean Air Act and its implementing regulations or of District Rules or both, as applicable.

(d) The permittee shall not use the "need to halt or reduce a permitted activity in order to maintain compliance" as a defense for noncompliance with any permit condition.

(e) A pending permit action or notification of anticipated noncompliance does not stay any permit condition.

(f) Within a reasonable time period, the permittee shall furnish any information requested by the Control Officer, in writing, for the purpose of determining:

(i) compliance with the permit, or
(ii) whether or not cause exists to modify, revoke and reissue, or terminate a permit or for an enforcement action.

(g) In the event that any condition herein is determined to be in conflict with any other condition contained herein, then if principles of law do not provide to the contrary, the condition most protective of air quality and public health and safety shall prevail.
[*Re: 40 CFR Part 70.6.(a)(6)(iii), District Rules 102, 1303.D.1.j, 1303.D.1.n, 1303.D.1.l, 1303.D.1.k, 1303.D.1.o*]

A.2 **Emergency Provisions.** The permittee shall comply with the requirements of the District, Rule 505 (Upset/Breakdown rule) and/or District Rule 1303.F, whichever is applicable to the emergency situation. In order to maintain an affirmative defense under Rule 1303.F, the permittee shall provide the District, in writing, a "notice of emergency" within 2 working days of the emergency. The notice of emergency shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. [*Re: District Rule 1303.F*]

A.3 **Compliance Plan.**

(a) The permittee shall comply with all federally enforceable requirements that become applicable during the permit term, in a timely manner.

(b) For all applicable equipment, the permittee shall implement and comply with any specific compliance plan required under any federally enforceable rules or standards.

[*Re: District Rule 1302.D.2*]

A.4 **Right of Entry.** The Regional Administrator of USEPA, the Control Officer, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises where a Part 70 source is located or where records must be kept:

(a) To inspect the stationary source, including monitoring and control equipment, work practices, operations, and emission-related activity;

(b) To inspect and duplicate, at reasonable times, records required by this Permit to Operate;

(c) To sample substances or monitor emissions from the source or assess other parameters to assure compliance with the permit or applicable requirements, at reasonable times. Monitoring of emissions can include source testing.

[*Re: District Rule 1303.D.2.a*]

A.5 **Severability.** The provisions of this Permit to Operate are severable and if any provision of this Permit to Operate is held invalid, the remainder of this Permit to Operate shall not be affected thereby. [*Re: District Rules 103, 1303.D.1.j*]

A.6 **Permit Life.** The Part 70 permit shall become invalid three years from the date of issuance, unless a timely and complete renewal application is submitted to the District. Any operation of the source to which this Part 70 permit is issued beyond the expiration date of this Part 70 permit and without a valid Part 70 operating permit (or a complete Part 70 permit renewal application) shall be a violation of the CAAA, § 502(a) and 503(d) and of the District rules.

The permittee shall apply for renewal of the Part 70 permit no later than 6 months before the date of the permit expiration. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. [*Re: District Rules 1304.D.1.*]

A.7 **Payment of Fees.** The permittee shall reimburse the District for all its Part 70 permit processing and compliance monitoring expenses for the stationary source on a timely basis. Failure to reimburse on a timely basis shall be a violation of this permit and of applicable requirements and can result in forfeiture of the Part 70 permit. Operation without a Part 70 permit subjects the source to potential enforcement action by the District and the USEPA pursuant to section 502(a) of the Clean Air Act. [*Re: District Rules 1303.D.1.p, 1304.D.11 and 40 CFR 70.6(a)(7)*]

A.8 Deviation from Permit Requirements. The permittee shall submit a written report to the District documenting each and every deviation from the requirements of this permit or any applicable federal requirements within 7 days after discovery of the violation, but not later than 180 days after the date of occurrence. The report shall clearly document 1) the probable cause and extent of the deviation 2) equipment involved, 3) the quantity of excess pollutant emissions, if any, and 4) actions taken to correct the deviation. The requirements of this condition shall not apply to deviations reported to District in accordance with Rule 505 *Breakdown Conditions,* or Rule 1303.F *Emergency Provisions.* *[Re: District Rule 1303.D.1.g, 40 CFR 70.6(a)(3)(iii)(B)]*

A.9 Federally-enforceable Conditions. Each federally enforceable condition in this permit shall be enforceable by the USEPA and members of the public. None of the conditions in the District-only enforceable section of this permit are federally enforceable or subject to the public/USEPA review *[Re: CAAA, § 502(b)(6), 40 CFR 70.6(b)]*

A.10 Reporting Requirements/Compliance Certification.
The permittee shall submit compliance certification reports to the USEPA *annually* and to the Control Officer *semi-annually*. These reports shall be submitted on District forms and shall identify each applicable requirement/condition of the permit, the compliance status with each requirement/condition, the monitoring methods used to determine compliance, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations (excluding emergency upsets) from permit requirement. The reporting periods shall be each half of the calendar year, e.g., January through June for the first half of the year. These reports shall be submitted by September 1 and March 1, respectively, each year. Supporting monitoring data shall be submitted in accordance with the "Semi-Annual Compliance Verification Report" condition in section 9.C. The permittee shall include a written statement from the responsible official, which certifies the truth, accuracy, and completeness of the reports. *[Re: District Rules 1303.D.1, 1302.D.3, 1303.2.c]*

A.11 Recordkeeping Requirements. The permittee shall maintain records of required monitoring information that include the following:

(a) The date, place as defined in the permit, and time of sampling or measurements;
(b) The date(s) analyses were performed;
(c) The company or entity that performed the analyses;
(d) The analytical techniques or methods used;
(e) The results of such analyses; and
(f) The operating conditions as existing at the time of sampling or measurement;

The records (electronic or hard copy), as well as all supporting information shall be maintained for a minimum of five (5) years from date of initial entry by SoCalGas and shall be made available to the District upon request. *[Re: District Rule 1303.D.1.f]*

A.12 Conditions for Permit Reopening. The permit shall be reopened and revised for cause under any of the following circumstances:

(a) Additional Requirements: If additional applicable requirements (e.g., NSPS or MACT) become applicable to the source which has an unexpired permit term of three (3) or more years, the permit shall be reopened. Such a reopening shall be completed no later than 18 months after promulgation of the applicable requirement. However, no such reopening is required if the effective date of the requirement is later than the date on which the permit is due to expire, unless the original permit or any of its terms and conditions has been extended. All such re-openings shall be initiated only after a 30 day notice of intent to reopen the permit has been provided to the permittee, except that a shorter notice may be given in case of an emergency.

(b) Inaccurate Permit Provisions: If the District or the USEPA determines that the permit contains a material mistake or that inaccurate statements were made in establishing the emission standards or other terms or conditions of the permit, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

(c) Applicable Requirement: If the District or the USEPA determines that the permit must be revised or revoked to assure compliance with any applicable requirement including a federally enforceable requirement, the permit shall be reopened. Such re-openings shall be made as soon as practicable.

Administrative procedures to reopen and revise/revoke/reissue a permit shall follow the same procedures as apply to initial permit issuance. Re-openings shall affect only those parts of the permit for which cause to reopen exists. If the permit is reopened, and revised, it will be reissued with the expiration date that was listed in the permit before the re-opening.
[*Re: 40 CFR 70.7(f)(1)-(3), 40 CFR 70.6(a)(2)*]]

A.13 Recordkeeping. All records and logs required by this permit and any applicable District, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the facility. These records or logs shall be readily accessible and be made available to the District upon request. [*Re: District Rule 1303, 40 CFR 70.6*]

9.B *Generic Conditions*

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. In case of a discrepancy between the wording of a condition and the applicable District rule, the wording of the rule shall control.

B.1 **Circumvention (Rule 301).** A person shall not build, erect, install, or use any article, machine, equipment or other contrivance, the use of which, without resulting in a reduction in the total release of air contaminants to the atmosphere, reduces or conceals an emission which would otherwise constitute a violation of Division 26 (Air Resources) of the Health and Safety Code of the State of California or of these Rules and Regulations. This Rule shall not apply to cases in which the only violation involved is of Section 41700 of the Health and Safety Code of the State of California, or of District Rule 303.

B.2 **Visible Emissions (Rule 302).** SoCalGas shall not discharge into the atmosphere from any single source of emission any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

(a) As dark or darker in shade as that designated as No. 1 on the Ringelmann Chart, as published by the United States Bureau of Mines, or

(b) Of such opacity as to obscure an observer's view to a degree equal to or greater than does smoke described in subsection B.2.(a) above.

For the equipment listed below, SoCalGas shall determine compliance with this Rule as specified below:

- *Flares.* For both of its planned and unplanned flaring, SoCalGas shall perform a USEPA Method 9 visible emission evaluation (VEE) annually. The VEE shall be for a six-minute period or the duration of the flaring event, whichever is shorter.
- *Diesel Fueled IC Engines.* SoCalGas shall perform a USEPA Method 9 visible emission evaluation (VEE) for a six-minute period annually.

SoCalGas staff or its contractor, certified in VEE, shall perform the VEE and maintain logs in accordance with USEPA Method 9. SoCalGas shall obtain District approval of the VEE log required by this condition. The start-time, end-time and the date of each visible emissions inspection shall be recorded in the log. All VEE sheets and records shall be maintained consistent with the recordkeeping condition of this permit. [*Re: District Rule 302*].

B.3 **Nuisance (Rule 303).** No pollutant emissions from any source at SoCalGas shall create nuisance conditions. No operations shall endanger health, safety or comfort, nor shall they damage any property or business.

B.4 **PM Concentration - South Zone (Rule 305).** SoCalGas shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in Table 305(a) of Rule 305.

B.5 **Specific Contaminants (Rule 309).** SoCalGas shall not discharge into the atmosphere from any single source sulfur compounds, carbon monoxide and combustion contaminants in excess of the applicable standards listed in Sections A, E and G of Rule 309.

B.6 Sulfur Content of Fuels (Rule 311). SoCalGas shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd or 15 grains per 100 cubic feet (measured as H_2S at standard conditions) for 'gaseous fuel' or fuel gas to the combustion units. Compliance with this condition shall be based on *periodic* measurements of the fuel gas and gaseous fuel using District-approved methods, and vendor-submitted data showing certified sulfur content for diesel.

B.7 Organic Solvents (Rule 317). SoCalGas shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on compliance by SoCalGas with Condition C.10 of this permit.

B.8 Solvent Cleaning Operations (Rule 321). This rule stipulates equipment and operational standards for process activities using solvents. SoCalGas shall comply with its Part 70 permit application 9584 statement that, except for routine maintenance involving wipe cleaning etc., it does not operate any solvent cleaning unit at the facility subject to Rule 321.

B.9 Architectural Coatings (Rule 323). SoCalGas shall comply with the coating ROC content and handling standards listed in Section D of Rule 323 as well as the Administrative requirements listed in Section F of Rule 323. Compliance with this condition shall be based on compliance by SoCalGas with Condition C.10 of this permit and facility inspections.

B.10 Disposal and Evaporation of Solvents (Rule 324). SoCalGas shall not dispose through atmospheric evaporation of more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on compliance by SoCalGas with Condition C.10 of this permit and facility inspections.

B.11 Adhesives and Sealants (Rule 353). The permittee shall not use adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless the permittee complies with the following:

A) Such materials used are purchased or supplied by the manufacturer or suppliers in containers of 16 fluid ounces or less; or alternately
B) When the permittee uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353, Section B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by record keeping in accordance with Section B.2 and/or Section O of Rule 353.

B.12 Large Water Heaters and Small Boilers (Rule 360). Any boiler, water heater, steam generator, or process heater rated greater than or equal to 75,000 Btu/hr and less than or equal to 2.000 MMBtu/hr and manufactured after October 17, 2003 shall be certified per the provisions of Rule 360. An ATC/PTO permit shall be obtained prior to installation of any grouping of boilers, water heaters, steam generators, or process heaters subject to Rule 360 whose combined system design heat input rating exceeds 2.000 MMBtu/hr.

B.13 Breakdowns (Rule 505). SoCalGas shall promptly report: (a) breakdowns that result in violations of emission limitations or restrictions prescribed by District Rules or by this permit, or (b) any in-stack, continuous monitoring equipment breakdowns; such reporting shall be made in conformance with the requirements of Rule 505, Sections A, B1 and D.

B.14 Emergency Episode Plan (Rule 603). During emergency episodes, SoCalGas shall implement the most current District-approved *Emergency Episode Plan*.

9.C Requirements and Equipment Specific Conditions

Federally-enforceable conditions, including emissions and operations limits, monitoring, recordkeeping and reporting are included in this section for each specific group of equipment. This section may also contain other non-generic conditions.

C.1 Internal Combustion Engines Providing Emission Reduction Credits (ERCs). The following IC engine equipment items are included in this emissions unit category:

Table C.1-1 — IC Engines *Providing Emission Reduction Credits (ERCs)*

District IDS #	Plant ID #	Equipment Item (IC Engine) Description
1199	#2	Ingersoll-Rand LVG-82, SN 8AL126; 650 hp gas compressor
1200	#3	Ingersoll-Rand LVG-82, SN 8AL129; 650 hp gas compressor
1201	#4	Ingersoll-Rand LVG-82, SN 8AL128; 650 hp gas compressor
1202	#5	Ingersoll-Rand LVG-82, SN 8AL127; 650 hp gas compressor
1203	#6	Ingersoll-Rand KVG-62, SN 6EL265; 660 hp gas compressor
1204	#7	Ingersoll-Rand KVG-62, SN 6EL266; 660 hp gas compressor
1205	#8	Ingersoll-Rand KVG-62, SN 6EL267; 660 hp gas compressor

(a) **Emission Limitations.** Mass emissions from the IC engines with Plant ID #s 2 through 8 shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Allowable pollutant emission concentrations for the same engines are listed below. Compliance with these limits shall be assessed through compliance with the monitoring (includes source testing requirements, the *ICE I&M Plan*, and the *CAM Plan*), record keeping and reporting conditions listed below in this permit.

Table C.1-2 - Emission Concentration Limits for IC Engines Providing ERCs

District IDS #	Plant ID #	Rich or Lean Burn?	Pollutant Name	Emission Limit: Concentration (ppmvd)	Emission Limit: Mass Rate (lbs/hr)
1199 thru 1205	#2 - #8	Rich Burn	*NOx*	*50 ppmv @ 15% O_2 or 90% control and 0.324 lb/MMBtu*	2.37
1199 thru 1205	#2 - #8	Rich Burn	*ROC*	*250 ppmv @ 15% O_2 and 0.32 lb/MMBtu*	2.34
1199 thru 1205	#2 - #8	Rich Burn	*CO*	*1,700 @ 15% O_2*	27.92

SoCal Gas may demonstrate compliance with the NO_x emission limits listed above either by meeting the exhaust concentration limit, or by both demonstrating at least 90% control of NO_x across the catalyst and meeting the emission factor limit of 0.324 lb/MMBtu.

(b) **Operational Restrictions.** The equipment permitted herein is subject to the following operational restrictions:

(i) *Fuel Use* — Only natural gas shall be used as fuel in the IC engines listed above.

(ii) *Engine Identification* — Each internal combustion engine shall have an identification plate or tag permanently affixed listing the make, model and serial number (or the operator's tag number). During any inspection, all identification plates or tags shall be made accessible and legible to facilitate District inspection of the engine.

(iii) *Heat Input Limits* — The following heat input limits apply to the IC engines:

District IDS #	Plant ID #	Maximum Hourly Heat Input *(MMBtu/hour)*	Maximum Annual Heat Input *(MMBtu/year)*
1199 through 1205	#2 – #8	7.30 for each engine	63,948 for each engine

(iv) *Inspection And Maintenance Plan (I&M Plan)* — The permittee shall operate in accordance with the District-approved, Rule 333.F. required, IC engine *Inspection and Maintenance Plan* and any subsequent District-approved updates.

(v) *Catalyst Operation* — For all IC engines above, (i.e., Engines # 2 through # 8) equipped with three-way NSCR catalysts, the catalysts shall operate at all times the engines are operating to reduce exhaust emissions of NO_x, ROC and CO from these engines.

(vi) *IC Engines Providing ERCs* — For all IC engines above, the following operational limits shall apply to ensure appropriate Emission Reduction Credits to the Point Arguello Project:

A. <u>Air-Fuel Ratio Controllers</u> — Each Air-Fuel Ratio Controller (AFRC) shall be operated, calibrated, and maintained at all times in accordance with manufacturer's recommendations.

B. <u>Oxygen Sensors</u> — Oxygen sensors in the stack shall be replaced by SoCalGas according to the schedule in the *IC Engine I&M Plan*. The date of each replacement shall be recorded in the maintenance log and quarterly reports, and this data shall be made available to the District inspector upon request.

C. <u>Engine/Catalyst Operation</u> – The performance standards of each NOx emission control device shall be maintained consistent with the *IC Engine I&M Plan.*

D. <u>Maintenance Of Engines</u> — Each engine shall be maintained in conformance with the permittee-designed operations and maintenance procedures necessary to minimize the pollutant emissions from the engine. A copy of these procedures shall be made available to the District upon request. For each engine, records shall be kept to document the maintenance activities along with any District-approved adjustment to the operations and maintenance procedures which may change the emissions. These maintenance and adjustment records shall be submitted to the District upon request.

E. Replacement Reporting —SoCalGas shall inform the District via telephone within 24 hours and in writing within five working days of any replacement of the engines or their associated control equipment. Replacement of the engines or their associated control equipment is only allowed in accordance with the District Rules and Regulations. If an engine is replaced, source testing shall be conducted in accordance with the procedures set forth in the source testing condition of this permit. Source testing shall be conducted within 60 calendar days of replacement to determine the actual emission reduction associated with the new equipment. This source testing shall be in addition to, and not a replacement of, the annual source test as required by Section 9.C.1(c)(i) of this permit. If a catalyst element is replaced, monitoring shall be conducted in accordance with the procedures specified in Appendix A of the *IC Engine I&M Plan*.

F. Emission Reduction Credits Dedicated To Point Arguello Project — The emission reduction credits created by District PTO 7500 are offsets for use by the Point Arguello Project, to meet its offset requirements. Emission reduction measures implemented to create the above emission reductions shall be maintained according to the *IC Engine I&M Plan*. The emission reduction credits are valid for the life of the Point Arguello Project only.

G. Shifts In Load — To assure that offsets in District PTO 7500 are real, quantifiable, surplus, and enforceable, SoCalGas shall not utilize a shift in load from the controlled engines with Plant ID #'s 2 - 8 to other uncontrolled point sources at the stationary source as means of generating possible additional emission reduction credits (ERCs).

For the purposes of this condition, shift in load is defined as a redirecting of fuel from a controlled emission unit to an uncontrolled emission unit for the sole purpose of increasing the uncontrolled emission unit's baseline fuel usage resulting in the generation of false surplus ERCs. If such shift in load does occur, the increased emissions at the uncontrolled emission unit shall not be considered in any baseline calculation for possible ERC for that uncontrolled emission unit.

H. Monitoring Of Engine Operation — Each engine shall be equipped with a non-resettable hour meter to record its hours of operation.

(c) **Monitoring**: The equipment permitted herein is subject to the following monitoring requirements:

(i) *Limits Exceedance* — Any District-certified IC engine source test result which indicates the applicable Rule 333 emission limits or NSR permit-specified limits (as specified in Table 5.1-3) have been exceeded shall constitute a violation of this permit.

(ii) *Compliance Assurance Monitoring:* SoCalGas shall implement the following CAM required monitoring:

A. Monitor all compliance assurance indicators for the engines in conformance with the requirements listed in the CAM Plan.

B. Log any excursions of each indicator from its limits that are set forth in the latest CAM Plan.

C. Log all periods of monitor shutdowns, monitoring malfunctions and associated monitor repairs and any required quality assurance/quality control activity periods for the monitors (i.e., the AFRC controller and the catalyst thermocouple units) as listed in the CAM Plan [*Ref: 40 CFR 64.7.(c)*]. The reason for each shutdown, e.g., indicator range excursion or malfunction, shall also be listed in the log.

D. Per 40 CFR 64.6.(c)(4), a minimum 90 percent data capture rate on a quarterly basis is required for each indicator. For the purposes of minimum data capture computations, any data obtained during the following periods are not included:
   - Routine monitor calibrations and inspections;
   - Sudden and infrequent monitor malfunctions beyond the operator's reasonable control [Ref: 40 CFR 64.7(c)]; and,
   - IC engine start-up periods.

E. A Quality Improvement Plan (QIP) is triggered for any engine subject to CAM Rule, if more than one (1) percent *[per 40 CFR 64.8 (a)]* of valid individual data points obtained in any calendar quarter lie outside the CAM Plan established indicator ranges. SoCalGas shall immediately notify the District if a QIP has been triggered and shall develop and submit such a Plan to the District for approval as expeditiously as practicable. The QIP submitted by SoCalGas shall meet all the requirements specified for it in 40 CFR Section 64.8 [*QIP Requirements*], at a minimum.

(iii) *General Monitoring* — For the I.C engines listed in Table C.1-1 above, the following monitoring requirements apply:

A. *Inspection and Maintenance Plan* — SoCalGas shall implement all monitoring provisions of its *IC Engine Inspection and Maintenance Plan* approved by the District. This includes emissions monitoring of the 7 engines per District Rule 333.F.3.The inspections shall be conducted prior to any adjustments to the AFRC set points and shall consist of one (1) fifteen minute run at the previously established set point.

B. *Fuel Heating Value* — The gross heating value of the gaseous fuel (Btu/scf) shall be measured using approved ASTM or ARB-approved test methods semi-annually.

C. *Fuel Sulfur Content* — The total sulfur content and H_2S content of the gaseous fuel burned on the property shall be determined semi-annually using approved ASTM or ARB-approved test methods.

D. *Operating Hours* — The hours of operation each month of each engine shall be documented in a log.

E. *Fuel Use Metering* — Fuel use for each engine shall be monitored by an in-line fuel meter. Meter design and specifications shall be approved by the District. The meters shall be calibrated per the latest District-approved *Process Monitor Calibration and Maintenance Plan.*

(d) **Recordkeeping**: The permittee shall record and maintain the following information. This data shall be maintained for a minimum of five (5) years from the date of each entry and made available to the District upon request:

(i) *Hours* — Records documenting hours of operation and days of operation for each IC engine each month. The record shall document any 60-minute start-up period required for the IC engine after it is shut-down.

(ii) *Fuel Use* — Records documenting IC engine(s) monthly fuel consumption (scf/month).

(iii) *Fuel Heating Value* — Records documenting the gross heating value of fuel (Btu/scf) on a semi-annual basis.

(iv) *Fuel Sulfur Content* — Records documenting the total sulfur content and H2S content of the gaseous fuel on a semi-annual basis.

(v) *Equipment Maintenance Data* — Records summary documenting engine/control device maintenance on an annual basis.

(vi) *I&M Plan Logs* — Logs documenting the parameter settings, NOx and CO level recorded, and other values required under the *Inspection and Maintenance Plan* for each engine shall be kept on-site.

(vii) *Equipment ID/Tags* — If an operator's tag number is used in lieu of an IC engine identification plate, written documentation which references the operator's unique IC engine ID number to a list containing the make, model, rated maximum continuous BHP and the corresponding RPM.

(viii) *Monitor Non-operational Time* – Logs documenting all non-operational times for the AFRC controller units and the catalyst temperature measurement units including the reasons for all monitor shutdowns, as monitored per Condition 9.C.1.(c)(ii)(C) above.

(ix) *Set Point Settings Data* — A record of the most current Air Fuel Ratio Controller set points and the date these were established.

(x) *Engine Operation Outside Settings* — A record of any continuous engine operation outside of the indicator ranges established in the CAM Plan. All such excursions are to be flagged specifically in the CAM logs.

(xi) *Maintenance Records* — Records on all maintenance performed for all equipment specified in this permit including engine time settings, engine maintenance, catalyst maintenance, and air-fuel ratio controller.

(xii) *Control Equipment Parameters* — Records on catalyst (including manufacturer, model and serial numbers), engine, air-fuel ratio controller, or sensor replacement.

(xiii) *CAM Plan Required Data* – A monthly summary of all compliance indicator data excursions and all monitor non-operational times, obtained pursuant to Conditions 9.C.1 (c)(ii)B and C above.

(e) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.2 Internal Combustion Engines Not Providing ERCs. The following IC engine equipment items are included in this emissions unit category:

Table C.2-1 — IC Engines not Providing ERCs

District IDS #	Plant ID #	Equipment Item (IC Engine) Description
1206	#9	Cooper-Bessemer GMV-10C; 1,100 hp gas compressor
*1221**	*#4A*	*Waukesha VRG-220U; 48 hp driving air compressor*
*1222**	*#5A*	*Waukesha VRG-220U; 48 hp driving air compressor*
*8665**	*Emergency Generator*	*Waukesha F817GU; 160 hp*

**-- Items in italics are District permit-exempt; however, they are not District Rule exempt*

Table C.2-2 - Emission Concentration Limits for IC engines not Providing ERCs

District ID #	Plant ID #	Rich or Lean Burn?	Pollutant Name	Emission Limit: Concentration (ppmvd)	Emission Limit: Mass Rate (lbs/hr)
1206	#9	*Lean Burn*	*NOx*	*125 @ 15% O2*	4.61
			VOC (ROC)	*750 @ 15% O2*	25.00
			CO	*4,500 @ 15% O2*	101.45

(a) **Emission Limits:** Mass emissions from the IC engine Plant ID # 9 shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Allowable pollutant emission concentrations for the engine are listed in Table C.2-2 above. Compliance with these limits shall be assessed through compliance with the monitoring (includes source testing and *ICE I&M Plan*), record keeping and reporting conditions listed below in this permit.

(b) **Operational Limits:** The operational limitations listed below shall apply to the IC engine (Plant ID # 9) listed in Table C.2-1 above. Compliance with these limits shall be assessed through compliance with the monitoring, record keeping and reporting conditions listed in this permit section.

(i) *Fuel Use* — Only natural gas shall be used as fuel.

(ii) *Engine Identification* — Each internal combustion engine shall have an identification plate or tag permanently affixed listing the make, model and serial number (or the operator's tag number). During any inspection, all identification plates or tags shall be made accessible and legible to facilitate District inspection of the engine.

(iii) *Heat Input Limits* — The following heat input limits apply to the IC engine Plant ID # 9: 10.02 MMBtu per hour and 87,795 MMBtu per year.

(iv) *Inspection And Maintenance Plan (I&M Plan)* — The permittee shall operate in accordance with the District-approved, Rule 333.F required IC engine Inspection and Maintenance Plans and their subsequent District-approved updates for all IC engines subject to Rule 333.

(c) **Monitoring:** The following source testing and monitoring conditions apply:

(i) *Limits Exceedance* — Any District-certified IC engine source test result which indicates the applicable Rule 333 emission limits or NSR permit-specified limits (as specified in Table 5.1-3) have been exceeded shall constitute a violation of this permit.

(ii) *I&M Plan* — SoCalGas shall implement all monitoring provisions of its *IC Engine I&M Plan* approved by the District.

(iii) *Fuel Heating Value* — The gross heating value of the gaseous fuel (Btu/scf) shall be measured using approved ASTM or ARB-approved test methods annually.

(iv) *Fuel Sulfur Content* — The total sulfur content and H_2S content of the gaseous fuel burned on the property shall be analyzed and determined annually using approved ASTM or ARB-approved test methods.

(v) *Operating Hours* — The hours of operation each month of each engine, including the IC engines exempt from permitting, shall be documented in a log. The log shall be made available for inspection upon request.

(vi) *Fuel Use Metering*— Fuel use for the engine with plant ID #9 shall be monitored by an in-line fuel meter. Meter design and specifications shall be approved by the District. The meters shall be calibrated per the latest District-approved *Process Monitor Calibration and Maintenance Plan.*

(d) **Recordkeeping**: SoCalGas shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring requirements above. All logs shall be available to the District upon request. Written information (logs) shall include:

(i) *Hours* — Records documenting individual IC engine operating hours each month.

(ii) *Fuel Use* — Records documenting IC engine Plant ID # 9 monthly fuel consumption (scf/month).

(iii) *Fuel Heating Value* — Records documenting the gross heating value of fuel (Btu/scf) on an annual basis.

(iv) *Fuel Sulfur Content* — Records documenting the total sulfur content and H2S content of the gaseous fuel on an annual basis.

(v) *Equipment Maintenance Data* — Records summary documenting engine/control device maintenance on an annual basis.

(vi) *I&M Plan Logs* — Logs documenting the parameter settings, NOx and CO level recorded, and other values required under the *Inspection and Maintenance Plan* for the engine shall be kept on-site.

(vii) *Equipment ID/Tags* — If an operator's tag number is used in lieu of an IC engine identification plate, written documentation which references the operator's unique IC engine ID number to a list containing the make, model, rated maximum continuous BHP and the corresponding RPM.

(e) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.3. Micro-Turbines. The following equipment is included in this emissions unit category:

Device No	Name
107543	#1: Capstone C60, Micro-Turbine, 60 kW / 0.804 MMBtu/hr
107544	#2: Capstone C60, Micro-Turbine, 60 kW / 0.804 MMBtu/hr
107545	#3: Capstone C60, Micro-Turbine, 60 kW / 0.804 MMBtu/hr
107546	#4: Capstone C60, Micro-Turbine, 60 kW / 0.804 MMBtu/hr

(a) **Emission Limits**: The mass emissions from the equipment permitted herein shall not exceed the values in Table 5.2. Compliance with the short-term and long-term mass emission limits for the Capstone C60 micro-turbines shall be based on the aggregated potential to emit of all four units. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit.

Based on CARB DG-002, emissions from the Capstone C60 micro-turbines shall not exceed 0.5 lb/MW-hr NO_x, 6 lb/MW-hr CO, and 1 lb/MW-hr ROC.

(b) **Operational Limits**: The permitted equipment is subject to the following operational restrictions:

(i) *PUC Quality Natural Gas Fuel Sulfur Limit*. The total sulfur and hydrogen sulfide (H_2S) content (calculated as H_2S at standard conditions, 60°F and 14.7 psia) of the PUC quality natural gas used as fuel in the Capstone C60 micro-turbines shall not exceed 80 ppmv and 4 ppmv, respectively. Compliance with this condition shall be based on annual fuel gas sampling and analysis.

(ii) *Fuel Type Restrictions*. The Capstone C60 micro-turbines shall only be operated using PUC quality natural gas. The permittee shall comply with the following fuel gas operational restrictions: The four Capstone C60 micro-turbines combined shall not use more than 73,508 scf/day, 6.71 MMscf/qtr, and 26.83 MMscf/yr of natural gas.

(c) **Monitoring:** The permitted equipment is subject to the following monitoring requirements:

(i) *Fuel Usage Metering*. The permittee shall install and operate a dedicated, temperature and pressure-corrected, totalizing, non-resettable type fuel meter, to measure the amount of natural gas used.

(ii) *Heating Value Data*. On an annual basis maintain record of the heat content (HHV) basis of the fuel gas in units of Btu/scf.

(iii) *Fuel Gas Sulfur Data*. The permittee shall measure the total sulfur and H_2S content of the fuel gas annually in accordance with EPA Methods 15/16/16A.

(iv) *Source Testing*. When requested in writing by the District the permittee shall source test the C60 micro-turbines to demonstrate compliance with Condition 9.C.3 (a) above. Table.4.4 of this PTO shows the pollutants and process parameters that are to be monitored when the micro-turbines are source tested.

(d) **Recordkeeping**: The following records shall be maintained by the permittee and shall be made available to the District upon request:

(i) *Fuel Gas Use*. The total amount of PUC quality natural gas used between the four Capstone C60 micro-turbines shall be recorded on a monthly, quarterly, and annual basis in units of standard cubic feet and million Btus.

(ii) *Heat Content*. Record the annual heating value results of the fuel gas.

(iii) *Operational Days*. For each month, the number of days each micro-turbine operated.

(iv) *Sulfur Content*. The annual measured total sulfur and H_2S content, both in units of ppmvd, of the fuel gas burned in the micro-turbines.

(e) **Reporting:** On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the Semi-Annual Compliance Verification Reports condition of this permit.

C.4 **Process Heaters:** The following items are included in this emissions unit category:

Table C.4 — Process Heaters

District IDS #	Plant ID #	Equipment Item (IC Engine) Description
001214	HOH #1	Fulton Thermal Corporation 3.500 MMBtu/hr hot oil heater
107535	HOH #2	American Heating Company 2.200 MMBtu/hr hot oil heater

(a) **Emission Limitations.** The emissions from the equipment permitted herein shall not exceed the values listed in Tables 5.1-3 B and 5.1-4 B. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit.

(b) **Operational Restrictions.** The equipment permitted herein is subject to the following operational restrictions:

(i) *Heat Input Limits*. The hourly, daily and annual heat input limits to each unit shall not exceed the values listed in Table 5.1-1 B. These limits are based on the design rating of the unit and the annual heat input value as listed in the permit application. Unless otherwise designated by the District 1,050 Btu/scf shall be used for determining compliance.

(ii) *Public Utility Natural Gas Fuel Sulfur Limit*. The total sulfur and hydrogen sulfide (H_2S) content (calculated as H_2S at standard conditions, 60°F and 14.7 psia) of the public utility natural gas fuel shall not exceed 80 ppmv and 4 ppmv respectively. Compliance with this condition shall be based on billing records or other data showing that the fuel gas is obtained from a public utility gas company.

(iii) *Rule 361 Compliance – Existing Units*. The owner or operator of any unit requesting the low use exemption in Section D.2 shall comply with the requirement to submit a Rule 361 Compliance Plan for District review and approval prior to March 15, 2016. Fuel meters installed pursuant to the approved Rule 361 Compliance Plan shall be installed prior to December 31, 2016.

On or before January 20, 2019, the owner or operator of any existing unit shall:

A. For units subject to Section D.1 emission standards, apply for an Authority to Construct permit.

B. For units subject to the Section D.2 low use provision, provide the annual fuel heat input data for years 2017 and 2018.

Any existing unit that is replaced or modified is subject to requirements of Rule 361 and shall first obtain a District ATC permit prior to installation or modification.

(iv) *External Combustion Units – Permits Required.*

A. An ATC/PTO permit shall be obtained prior to installation of any grouping of Rule 360 applicable boilers or hot water heaters whose combined system design heat input rating exceeds 2.000 MMBtu/hr.

B. An ATC permit shall be obtained prior to installation, replacement, or modification of any existing Rule 361 applicable boiler or water heater rated over 2.000 MMBtu/hr.

C. An ATC shall be obtained for any size boiler or water heater if the unit is not fired on natural gas or propane.

(c) **Monitoring.** The equipment permitted herein is subject to the following monitoring requirements:

(i) *Default Rating Method.* The volume of natural gas used (in units of standard cubic feet) shall be reported as permitted annual heat input limit for the unit (Btu/year) divided by the District-approved heating value of the fuel (Btu/scf).

(ii) *Existing Units Rated Between 2.000 - 5.000 MMBtu/hr.* These units are not subject to tuning or source testing requirements.

(d) **Recordkeeping.** The permittee shall record and maintain the following information. This data shall be maintained for a minimum of five (5) years from the date of each entry and made available to the District upon request:

(i) *Fuel Use - Units Rated Under 5.000 MMBtu/hr.* The volume of fuel gas used each year (in units of standard cubic feet) as determined by the Default Rating Method.

(e) **Reporting.** On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the Semi-Annual Compliance Verification Reports condition of this permit.

C.5 **Flares.** The following equipment items are included in this emissions unit category:

Table C.5 — List of Flares

District IDS #	Equipment Item Description
1211	Flare – serving Glycol unit; 1.600 MMBtu/hr, pilot fired with PUC natl. gas
1212	Flare – serving Glycol unit; 1.600 MMBtu/hr, pilot fired with PUC natl. gas
1215	Flare; 1.600 MMBtu/hr, pilot fired with PUC natural gas
104915	SULFATREAT Unit; Cameron, Kleen Air, 46" dia. by 88" high, 4950 lbs.
113418	SULFATREAT Unit; Cameron, Kleen Air, 46" dia. by 88" high, 4950 lbs. (back-up)
104916	'CEI-KMN' Unit B; Cameron, Kleen Air, 46" diam. by 64" high, 2850 lbs
107706	'CEI-KMN' Unit C; Cameron, Kleen Air, 46" diam. by 64" high, 2850 lbs

(a) **Emission Limits:** Mass emissions from the equipment items listed above shall not exceed the limits listed in Tables 5.1-3B and 5.1-4B for the items. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions listed below in this permit.

(b) **Operational Limits:** The operational limitations listed below shall apply to the equipment items listed above. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions listed in this permit section.

(i) Flare units 1211 and 1212 shall not combust any waste gases that have not been treated by one of the SULFATREAT units (104915 or 113418) operating in series with one of the CEI-KMN units B (104916) or C (107706). CEI-KMN units B and C are designed to operate in parallel with each other; either one of these units shall operate all the time the waste gas stream is processed. SoCalGas must receive written District approval prior to using any alternate media in these units.

(ii) *Smokeless Operation*: All flares shall operate "smokeless," as defined in District Rule 359.C.

(iii) *Automatic Ignition:* All flares shall operate equipped with an automatic ignition system including a pilot-light gas source or equivalent system, or shall operate with pilot flames present at all times with the exception of purge periods for automatic ignition equipped flares.

(iv) *Flame Monitoring*: The presence of the flame in the flare pilots shall be continuously monitored using thermocouples or equivalent devices that detect the presence of flames.

(v) *Flame Operation*: The flare flames shall be operating at all times when combustible gases are vented through the flares.

(vi) *Heat Input:* The maximum hourly heat input to each flare is limited to the value listed below:

Flare ID#	Max. Hourly Heat Input (MMBtu/hr)
1211, 1212, 1215	1.600 (each flare)

(vii) *Gaseous Fuel Sulfur Limit:* The gases combusted in the flares shall not contain sulfur compounds in excess of 15 gr./100 scf (239 ppmv), calculated as H_2S under standard conditions (i.e., 14.7 psia and 60°F). Only PUC-quality natural gas shall be used as pilot fuel gas, with total sulfur content less than 80 ppmv.

(viii) The drains off of the SULFATREAT unit and the CEI-KMN units shall remain connected to the existing low pressure condensate piping system at all times. No liquids shall be drained to the atmosphere from the two units when they are operational; and no flash-offs to the atmosphere shall occur from these two units while operating and draining collected water.

(c) **Monitoring:** The following monitoring conditions apply to the flare equipment items:

(i) *Heating Value:* The heating value of the 'gaseous fuel' (Btu/scf) shall be analyzed annually using the ASTM methods listed in Rule 359.E (test methods).

(ii) *Fuel Sulfur Content:* For flare unit 1215, 'gaseous fuel' sulfur content (H_2S and TRS) must be measured annually using the ASTM methods listed in Rule 359.E (test methods). For flare units 1211 and 1212, the total sulfur content in 'gaseous fuel' shall be measured semi-annually using the Rule 359.E listed methods.

(iii) *Purge Gas Sulfur Content:* The purge gas sulfur content must be measured annually using Rule 359.E-listed ASTM methods, if such gas is not PUC quality natural gas or an inert gas.

(iv) *Media Bed Changes:* SoCalGas shall maintain purchase records documenting the type of material purchased for the SULFATREAT units and the CEI-KMN units.

(d) **Recordkeeping**: SoCalGas shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring requirements above. All logs shall be available to the District upon request. Written information (logs) shall include:

(i) *Heating Value*: Annual records documenting the higher heating value of the 'gaseous fuel.' Such documents shall be the results of the laboratory analyses using ASTM test methods prescribed in Rule 359.E.

(ii) *Fuel Sulfur Content:* Records documenting annually the 'gaseous fuel' sulfur content as measured periodically, and, if applicable, the purge gas sulfur content for each flare unit.

(iii) *Media Bed Change:* Records documenting any media bed changes for the SULFATREAT units and the CEI-KMN units. The records shall include the dates and times of each change-out, the quantity of material replaced, and the type of material placed in the unit.

(e) **Reporting:** On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.6 **Fugitive Hydrocarbon Emissions Components.** The following equipment units are addressed via the 'component-leak-path' methodology:

Table C.6 (Fugitive HC Components and Component-Leak-Paths)

District IDS #	Equipment Item Name	Description
	Gas & Light Liquid Service Components	
100882	Valves	*2,641 component-leak-paths*
100883	Connections	*18,339 component-leak-paths*
100884	Pump Seals	*2 component-leak-paths*
100885	Compressor Seals	*17 component-leak-paths*
100886	Pressure Relief Devices	*91 component-leak-paths*

(a) **Emission Limits**: Mass emissions from the fugitive HC components listed above shall not exceed the limits listed in Table 5.1-3 B and 5.1-4 B for these components.

(b) **Operational Limits**: Operation of the equipment listed in this section shall conform to the requirements listed below. Compliance with these limits shall be assessed through compliance with the monitoring, record-keeping and reporting conditions in this permit.

(i) *Gas Collection System Use* – The gas collection (GC) system shall be in operation when any of the equipment which is connected to the GC system at the facility is in use. The GC system shall be maintained and operated to minimize the release of emissions from all systems, including separators and storage vessels.

(ii) *Leak-Path Count* – The total component and component-leak-path count listed in the SoCalGas I&M component and component-leak-path inventory shall not exceed the total leak-path component count assigned to these units in Table C.6 by more than five percent. This five percent range is to allow for minor differences due to component counting methods and does not constitute allowable emissions growth due to the addition of new equipment. The leak path count in Table C.6 will be verified by the District during inspections.

(c) **Recordkeeping**: SoCalGas shall keep a log of the changes in fugitive emissions component count and the associated emissions changes summarized on a quarterly basis. All inspection and/or repair records shall be retained at the plant for a minimum of five years. In addition SoCalGas shall maintain the following records:

(i) *Carbon Canister Change:* Records documenting carbon replacement for the canister serving the odorant system. The records shall include the dates of each change-out, the quantity of material replaced, and the type of material placed in the unit.

(d) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.7 Hydrocarbon Liquid Storage Tanks. The following equipment items at the dehydration units are included in this emissions unit category:

Table C.7 — List of Storage Tank Emissions Units

District IDS #	Equipment Item Description
1219	Flotation Cell; 10,000 gallons capacity, 12' diameter, 12' high
1220	Flotation Cell; 10,000 gallons capacity, 12' diameter, 12' high
1217	HC condensate Storage Tank; 7,050 gallons, 10' diameter, 12' high
1218	Brine Water Storage Tank; 40,600 gallons, 24' diameter, 12' high
100899	Methanol Storage Tank; 500 gallons, blanketed with NG
100910	Glycol Contactor Control Tanks (3); pressurized, each 16" diam., 15.25' long
100910	Glycol Contactor Control Tank (1); pressurized, 16" diam., 17'8"' long
100901	Odorant Storage Tank (1); 1000 gallons, pressurized, storing Captan-50/thiophane

(a) **Emission Limits**: Mass emissions from the equipment items ID # 1219, 1220 and 1217 listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4 for the items. Compliance with these limits shall be assessed through compliance with the monitoring, record keeping and reporting conditions listed below in this permit.

(b) **Operational Limits**: The operational limitations listed below shall apply to the items listed above in this permit section. Compliance with these limits shall be assessed through compliance with the monitoring, record keeping and reporting conditions listed in this permit section.

(i) *Throughput Limitations*: Annual hydrocarbon condensate production (dry) shall not exceed 125,000 gallons.

(ii) *Vapor Recovery System Operation:* No volatile organic compound (VOC) liquid shall be stored in the hydrocarbon storage tanks (ID # 1219, 1220 and 1217) or brine water storage tank (ID # 1218) listed in Table C.7, unless the tanks are connected to the gas collection system and all collected gas is combusted by a flare with a destruction efficiency of at least 95%. All tanks listed in Table C.7 shall be operated in a leak-free condition to minimize the release of reactive organic vapors.

(iii) *Tank Clean Out:* Prior to opening a tank for cleaning the tank shall be purged of ROC vapors and the purged gas shall be directed to a vapor control device with a destruction efficiency of at least 95%.

(iv) *Odorant Tank Filling:* Emissions of VOCs to the atmosphere resulting from any odorant storage tank (ID # 100901) filling operations shall be reduced by passing displaced vapors through a vapor recovery system with control efficiency greater than 90 percent. Odorant emissions shall not be detectable, by olfactory senses, at or beyond the property boundary at any time during tank filling operations.

(c) **Monitoring:** The following monitoring conditions apply to items listed in Table C.6 above:

(i) *Hydrocarbon Liquid (Condensate) Volume*: The volume of hydrocarbon liquid (condensate) produced annually shall be monitored by noting the volume (in gallons) flowing out of the hydrocarbon liquid storage tank (ID # 1217) into trucks on a monthly basis.

(ii) *API Gravity & True Vapor Pressure Of Stored HC* — The API gravity and the true vapor pressure at 67.2 degrees F of the stored hydrocarbon liquid in each storage tank (ID # 1219, 1220 and 1217) shall be determined annually. Alternately, the Reid vapor pressure of the stored condensate may be measured by the ASTM D 323 Standard Method and the true vapor pressure calculated by API Bulletin 2517, or equivalent District-approved Reid/True vapor pressure correlation. The actual temperature of the stored hydrocarbon liquid shall be measured each time a sample is taken for API gravity and TVP analysis.

Note: The API gravity and TVP analysis for the HC Condensate Storage tank may be used as representative values for all three tanks instead of sampling from each tank individually.

(d) **Recordkeeping**: SoCalGas shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring requirements above. All logs shall be available to the District upon request. Written information (logs) shall include:

(i) *Hydrocarbon Liquid (Condensate) Volume*: The volume of hydrocarbon liquid produced annually shall be recorded

(ii) *API Gravity & True Vapor Pressure Of Stored HC* — The API gravity, the true vapor pressure at 67.2 degrees F, and the actual storage temperature of the stored hydrocarbon liquid in each storage tank (ID # 1219, 1220 and 1217) shall be recorded annually.

(iii) *Maintenance Records* — Records of maintenance performed per Sections B.3 and B.5 of Rule 326. These records contain, at a minimum, the following:

A. *Tank Identification*: Tank identification type of vapor controls used, and initials of personnel performing maintenance.
B. *Maintenance Performed*: Description of maintenance procedure performed.
C. *Estimated Excess Emissions*: Excess emissions caused by maintenance and how determined.

D. *Maintenance Dates & Times*: Times and dates of maintenance procedure.

(e) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.8 Loading Station. The following equipment item is included in this emissions unit category:

Table C.8 – Loading Station Unit

District IDS #	Equipment Item Name/Description
8669	Loading Station; Grade level station to load tankers, not VRU equipped

(a) **Emission Limits**: Mass emissions from the equipment items listed above shall not exceed the emission limit listed for these items in Tables 5.1-3 and 5.1-4 of this permit. Compliance with these limits shall be assessed through compliance with the monitoring, record-keeping and reporting (MRR) conditions listed in this permit.

(b) **Operational Limits**: All process operations from the equipment listed in this section shall meet the requirements of District Rule 346. The following addition operational limits apply:

(i) All tanker trucks receiving organic liquids shall be equipped with a submerged fill pipe;

(ii) SoCalGas shall restrict the HC condensate loading station operations so that the hourly volume of condensate into tanker trucks shall not exceed 170 barrels;

(iii) The condensate volume loading shall be restricted to 476 barrels (i.e., 19,992 gallons) daily; and

(iv) Total condensate loading volume shall not exceed 2,976.19 barrels (i.e., 125,000 gallons) annually.

Compliance with these limits shall be assessed through compliance with the monitoring, record-keeping and reporting conditions in this permit.

(c) **Monitoring:** SoCalGas shall monitor, via a log or a shipping invoices document, the daily and total annual volumes of hydrocarbon condensate shipment from the truck loading station.

(d) **Recordkeeping**: SoCalGas shall record the daily and total annual volumes (in gallons) of HC condensate shipment from the loading station, in a log kept on-site. When vacuum trucks are used to empty the condensate tanks, the log shall include the operator's initials, date of loading operation, and the destination of the condensate. If vacuum trucks are not used to empty the condensate tanks, the log shall include the operator's initials, date of loading operation, transfer temperature, and method of determining throughput for each loading operation.

(e) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must include all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.9 **Wells.** The following equipment items are included in this emissions unit category:

Table C.9 (Gas Wells)

District IDS #	Equipment Item Name/Description
8670	Miscellaneous Gas Wells: 21 in number, fugitive emissions
100903	Miscellaneous Stacks/Gas Vents: gas venting due to pipeline depressurization

(a) **Emission Limits**: Mass emissions from the emission units listed above shall not exceed the emission limit listed for these items in Tables 5.2B of this permit. Compliance with these limits shall be assessed through compliance with the monitoring, record-keeping and reporting (MRR) conditions listed in this permit.

(b) **Monitoring**: On an annual basis, SoCalGas shall (i) measure the reactive organic compound (ROC) content of the vented gas, using gas-liquid chromatography analysis, and the gas total sulfur (TRS) content, and (ii) annually record the computed volume of vented reservoir gas from each pipeline depressurization event.

(c) **Record Keeping**: SoCalGas shall record the following:

(i) The computed volume of gas (in units of scf) vented annually to the atmosphere resulting from all pipeline depressurizations; and the ROC and TRS content (by weight percent) of this gas.
(ii) The dates and volumes of venting attributed to emergency events, and documentation of each emergency.

(d) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.10 **Solvent Usage.** The following equipment are included in this emissions unit category:

District IDs #	Equipment Name/Description
8680	Cleaning/Degreasing

(a) **Emission Limits**: ROC mass emissions from solvent usage shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(b) **Operational Limits**: Use of solvents for cleaning/degreasing shall conform to the requirements of District Rules 317, 321, and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and through facility inspections.

(i) *Containers* - Vessels or containers used for storing materials containing organic solvents shall be kept closed unless adding to or removing material from the vessel or container.

(ii) *Materials* - All materials that have been soaked with cleanup solvents shall be stored, when not in use, in closed containers that are equipped with tight seals.

(iii) *Solvent Leaks* - Solvent leaks shall be minimized to the maximum extent feasible or the solvent shall be removed to a sealed container and the equipment taken out of service until repaired. A solvent leak is defined as either the flow of three liquid drops per minute or a discernible continuous flow of solvent.

(iv) *Reclamation Plan* - SoCalGas may submit a Plan to the District for the disposal of any reclaimed solvent. If the Plan is approved by the District, all solvent disposed of pursuant to the Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source. SoCalGas shall obtain District approval of the procedures used for such a disposal Plan. The Plan shall detail all procedures used for collecting, storing and transporting the reclaimed solvent. Further, the ultimate fate of these reclaimed solvents must be stated in the Plan.

(c) **Recordkeeping**: SoCalGas shall record in a log the following on a monthly basis for each solvent used: amount used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed for District-approved disposal; whether the solvent is photochemically reactive; and, the resulting emissions to the atmosphere in units of pounds per month and pounds per day. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be readily available.

(d) **Reporting**: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the District. The report must list all data required by the *Semi-Annual Compliance Verification Reports* condition of this permit.

C.11 Process Monitoring Systems - Operation and Maintenance. All Plant process monitoring devices listed in Section 4.9.2 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. SoCalGas shall implement a District-approved *Process Monitor Calibration and Maintenance Plan* for the life of the Plant.

C.12 Process Stream Sampling and Analysis. SoCalGas shall sample analyze the process streams listed in Section 4.10 of this permit according to the methods and frequency detailed in that Section. All process stream samples shall be taken according to ASTM or other District-approved methods and must follow traceable chain of custody procedures.

C.13 Source Testing. The following source testing provisions shall apply:

(i) SoCalGas shall conduct 'third party' source testing of air emissions and process parameters listed in Section 4.10 and Table 4.1 of this Permit to Operate. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCO, occur. A source test shall not be required for equipment that is documented to have been in out-of -service status, and is not operational at the time of annual source testing. However, when such equipment becomes operational, a source test shall be performed within 30 calendar days of start-up. The District shall be notified in writing at least 3 working days before the affected equipment will become operational.

(ii) SoCalGas shall submit a written source test plan to the District for approval at least thirty (30) calendar days prior to initiation of each source test. The source test plan shall be prepared consistent with the District's *Source Test Procedures Manual* (revised May 1990 and any subsequent revisions). If SoCalGas wants to demonstrate NOx emissions compliance for its IC engines #2 through #8 utilizing the 90% control option listed in Rule 333, the Plan shall include proposed procedures to measure simultaneously the catalyst inlet and outlet NOx concentrations. SoCalGas shall obtain written District approval of the source test plan prior to commencement of source testing. The District shall be notified at least fourteen (14) calendar days prior to the start of source testing activity to arrange for a mutually agreeable source test date when District personnel may observe the test.

(iii) A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include but are not limited to mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain District approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. Once the sample probe has been inserted into the exhaust stream of the equipment unit to be tested (or extraction of the sample has begun), the test shall proceed in accordance with the approved source test plan. In no case shall a test run be aborted except in the case of an emergency or unless approval is first obtained from the District. If the test cannot be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the District. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without District's authorization shall constitute a violation of this permit.

(iv) A source test report shall be submitted to the District within forty-five (45) calendar days following the date of source test completion and shall be consistent with the requirements approved within the source test plan. The source test report shall include all data and calculations to determine compliance with emission rates in Sections 5 and 9 and applicable permit conditions. All reasonable District costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by SoCalGas as provided for by District Rule 210.

(v) The District may, at its discretion, extend any of the timelines listed in this condition for good cause.

C.14 IC Engine Particulate Matter Operation & Maintenance Plan. To ensure compliance with District Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701 by the diesel-fired emergency fire-water pumps, SoCalGas shall implement its District-approved *IC Engine Particulate Matter Operation and Maintenance Plan* for the life of the project. [*Re: District Rules 205.A, 302, 304, 309*]

C.15 Semi-Annual Compliance Verification Reports. Twice a year, SoCalGas shall submit a compliance verification report to the District. Each report shall be used to verify compliance with the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and shall be submitted no later than September 1. The second report shall cover calendar quarters 3 and 4 (July through December) and shall be submitted no later than March 1. Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit (if applicable for that reporting period). These reports shall be in a format approved by the District, with one hard copy and one PDF copy. All logs and other basic source data not included in the report shall be available to the District upon request. The second report shall also include an annual report summarizing the activities for the calendar year. Pursuant to Rule 212, a completed *District Annual Emissions Inventory* questionnaire shall be included in the annual report or submitted electronically via the District web site.

The report shall include the following information:

(a) *Internal Combustion Engines.*
  (i) Records documenting hours of operation and days of operation for each IC engine each month. The record shall document any 60-minute start-up period.
  (ii) Records documenting each permitted IC engine's monthly fuel consumption (scf/month).
  (iii) The higher heating value of the fuel (Btu/scf) as measured by the most recent fuel analysis.
  (iv) The fuel sulfur content as measured by the most recent fuel analysis.
  (v) Documentation of any equivalent routine IC engine replacement.
  (vi) Summary results of all compliance emission source testing and inspections performed.
  (vii) A summary of CAM monitoring, including a count of all excursions each quarter.

(b) *Micro-Turbines.*
  (i) *Fuel Gas Use.* The total amount of PUC quality natural gas used between the four Capstone C60 micro-turbines shall be recorded on a monthly, quarterly, and annual basis in units of standard cubic feet and million Btus.
  (ii) *Heat Content.* The annual measured heating value of the fuel gas.
  (iii) *Operational Days.* For each month, the number of days each micro-turbine operated.
  (iv) *Sulfur Content.* The annual measured total sulfur and H_2S content, both in units of ppmv, of the fuel gas burned in the Capstone C60 micro-turbines.

(c) *Hot Oil Heaters.*
The volume of natural gas used (in units of standard cubic feet) shall be reported as permitted annual heat input limit for each unit (Btu/year) divided by the District-approved heating value of the fuel (Btu/scf).

(d) *Flares.*
  (i) *Heating Value*: Results of the most recent high heating value analysis.
  (ii) *Fuel Sulfur Content:* Records of the fuel gas and, if conducted, the purge gas sulfur analyses for each flare.
  (iii) *Media Bed Change:* Records documenting any media bed changes for the SULFATREAT unit and the CEI-KMN units. The records shall include the dates of each change-out, the quantity of material replaced, and the type of material placed in the unit.

(e) *Fugitive Hydrocarbon Emission Components.*
Changes in the fugitive emissions component count, the total component count, and the associated emission changes at the stationary source.

(f) *Hydrocarbon Liquid Storage Tanks.*

(i) The hydrocarbon liquid throughput for the prior two calendar quarters.

(ii) The API gravity, true vapor pressure at 67.2 degrees F, and the actual storage temperature of the stored hydrocarbon liquid in each storage tank.

(iii) Records of each tank maintenance.

(g) *Loading Station.*
The daily and annual volume of HC condensate loaded and the dates of shipments from the loading rack.

(h) *Wells/Venting.*
The volume (scf) of gas vented, the ROC and TRS content of the gas, and the weight (in pounds) of ROC and TRS vented.

(i) *Glycol Unit*
The total volume (in MMSCF units) of gas flow through the unit.

(j) *Solvent Usage.*
On a semi-annual basis: the amount of solvent used; the percentage of ROC by weight (as applied); the solvent density; the amount of solvent reclaimed; whether the solvent is photo-chemically reactive; and, the resulting emissions of ROC and photo-chemically reactive solvents to the atmosphere in units of pounds per month.

(k) *General Reporting Requirements.*

(i) On an annual basis, the emissions from each exempt emission unit for ROC and NO_x.

(ii) A summary of each and every occurrence of non-compliance with the provisions of this permit, District rules, and any other applicable air quality requirement (*for this purpose, any breakdown report submitted to the District per Regulation V for the non-compliance event need not be repeated; a brief reference will be sufficient*)

(iii) A summary list of breakdowns and variances reported/obtained per Regulation V along with the excess emissions that accompanied each occurrence.

(l) *Odorant System.*
Records documenting carbon replacement for the canister serving the odorant system. The records shall include the dates of each change-out, the quantity of material replaced, and the type of material placed in the unit.

C.16 Documents Incorporated by Reference. The documents listed below, including any District-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of Gas Plant.

(i) *IC Engine Particulate Matter Operation and Maintenance Plan.* (Ref: Permit condition 9.C.14)

(ii) *Emergency Episode Plan* (Rule 603) (*12/9/2008*).

(iii) *IC Engine I&M Plan* (12/12/2011)

(iv) *Process Monitor Calibration and Maintenance Plan.* (2/8/2012)

(v) *Processed Gas Flow Measurement Plan.* (2/8/2012)

(vi) *Compliance Assurance Monitoring (CAM) Plan.* (12/12/2011)

9. D *District-Only Conditions*

The following section lists permit conditions that are not enforceable by the USEPA or the public. However, these conditions are enforceable by the District and the State of California. These conditions are issued pursuant to District Rule 206 (*Conditional Approval of Authority to Construct or Permit to Operate*), which states that the Control Officer may issue an operating permit subject to specified conditions. These permit conditions have been deemed necessary to ensure that operation of the facility complies with all applicable local, and state air quality rules, regulations and laws. Failure to comply with any condition specified pursuant to the provisions of Rule 206 shall be a violation of that rule, this permit, as well as any applicable section of the California Health & Safety Code.

D.1 **Condition Acceptance.** Acceptance of this operating permit by SoCalGas shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: District Rule 206*]

D.2 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rule, regulation, ambient air quality standard or air quality increment.

D.3 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the District's project file) and the District's analyses, as shown in this permit, of the same under which this permit is issued.

D.4 **Consistency with Federal, State and Local Permits.** Nothing in this permit shall relax any applicable air pollution control requirement or mitigation requirement imposed on SoCalGas by any other governmental agency.

D.5 **Odorous Organic Sulfides.** SoCalGas shall not discharge into atmosphere H_2S and organic sulfides that result in a ground level impact beyond the SoCalGas property boundary in excess of either 0.06 ppmv averaged over 3 minutes or 0.03 ppmv averaged over 1 hour.

D.6 **Throughput Limit.** The total gas processed by dehy plant 14 shall not exceed 680 MMscf/day, calculated as monthly total gas processed at the plant divided by the number of gas processing days. The monthly gas volume flow shall be measured, using District-approved flow meter(s)/device(s). SoCalGas shall monitor the monthly total volume (in MMscf units) of gas processed and the number of processing days via a log to be kept on site. The calculated daily average volume of gas withdrawn/processed shall also be recorded in this log each month.

D.7 **Gas Venting.** Only gas from planned pipeline depressurizations may be vented without control. The total volume of gas vented from the facility due to planned pipeline depressurization shall not exceed 10 MMscf annually. If gas is vented without control from unplanned pipeline depressurizations the permittee may seek relief from this requirement under the provisions of Rule 505 or Rule 1303 F.

D.8 **Annual Reporting.**

(a) Plant-wide Gas Processing: Volume of gas withdrawn/processed per month, the number of days of withdrawal/processing per month and average daily volume (in MMscf) of gas withdrawn/processed for the month.

(b) The March annual report shall list total tons per year of each criteria pollutant emitted from each emissions unit.

D.9 Emergency Standby Firewater Pump Engines. The two equipment items listed below belong to this emissions unit category.

District IDS #	Plant ID #	Equipment Item Name/Description
8666	# 12A	133 bhp Cummins Model V-378-F2 diesel-fired emergency standby firewater pump engine
8668	# 13A	133 bhp Cummins Model V-378-F2 diesel-fired emergency standby firewater pump engine

(a) **Emission Limitations.** The mass emissions from the E/S DICE unit #s 008666 and 008668 listed above shall not exceed the values listed in Tables 5.1-3 and 5.1-4. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit.

(b) **Operational Restrictions.** The E/S DICE unit #s 008666 and 008668 listed above are subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[6], have no operational hours limitations.

(i) Maintenance & Testing Use Limit: The in-use stationary emergency standby diesel-fueled CI engines subject to this permit shall not be operated for more than 20 hours per year.

(ii) Fuel and Fuel Additive Requirements: The permittee may only add fuel and/or fuel additives to the engine or any fuel tank directly attached to the engine that comply with Section (e)(1)(B) of the ATCM.

(c) **Monitoring.** The E/S DICE unit #'s 008666 and 008668 listed above are subject to the following monitoring requirements:

Non-Resettable Hour Meter: Each in-use stationary emergency standby diesel-fueled CI engine(s) subject to this permit shall have installed a non-resettable hour meter with a minimum display capability of 9,999 hours, unless the District has determined (in writing) that a non-resettable hour meter with a different minimum display capability is appropriate in consideration of the historical use of the engine and the owner or operator's compliance history.

(d) **Recordkeeping.** The permittee shall record and maintain the information listed below. Log entries shall be retained for a minimum of 36 months from the date of entry. Log entries made within 24 months of the most recent entry shall be retained on-site, either at a central location or at the engine's location, and made immediately available to the District staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to District staff within 5 working days from request. District Form ENF-92 (*Diesel-Fired Emergency Standby Engine Recordkeeping Form*) can be used for this requirement.

(i) emergency use hours of operation;

(ii) maintenance and testing hours of operation;

[6] As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines

(iii) hours of operation for emission testing to show compliance with Section (e)(2)(B)(3) {if specifically allowed for under this permit}.
(iv) initial start-up hours {if specifically allowed for under this permit}.
(v) hours of operation to comply with the requirements of NFPA 25/100 {if applicable}.
(vi) hours of operation for all uses other than those specified in items (i) – (iv) above along with a description of what those hours were for.
(vii) The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:
A. identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above.
B. amount of fuel purchased.
C. date when the fuel was purchased.
D. signature of owner or operator or representative of owner or operator who received the fuel.
E. signature of fuel provider indicating fuel was delivered.

(e) **Reporting.** By March 1 of each year, a written report documenting compliance with the terms and conditions of this permit and the ATCM for the previous calendar year shall be provided by the permittee to the District (Attn: *Annual Report Coordinator*). All logs and other basic source data not included in the report shall be made available to the District upon request. The report shall include the information required in the Recordkeeping Condition above.

(f) **Temporary Engine Replacements - DICE ATCM.** Any reciprocating internal combustion engine subject to this permit and the stationary diesel ATCM may be replaced temporarily only if the requirements (i - vi) listed herein are satisfied.
(i) The permitted engine is in need of routine repair or maintenance.
(ii) The permitted engine that is undergoing routine repair or maintenance is returned to its original service within 180 days of installation of the temporary engine.
(iii) The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine that is being temporarily replaced. At the written request of the permittee, the District may approve a replacement engine with a larger rated horsepower than the permitted engine if the proposed temporary engine has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.
(iv) The temporary replacement engine shall comply with all rules and permit requirements that apply to the permitted engine that is undergoing routine repair or maintenance.
(v) For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form may be sent hardcopy, or can be e-mailed (e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).
(vi) Within 14 days upon return of the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form may be sent hardcopy, or can be e-mailed

(e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).

Any engine in temporary replacement service shall be immediately shut down if the District determines that the requirements of this condition have not been met. This condition does not apply to engines that have experienced a cracked block (unless under manufacturer's warranty), to engines for which replacement parts are no longer available, or new engine replacements {including "reconstructed" engines as defined in Section (d)(44) of the ATCM}. Such engines are subject to the provisions of New Source Review and the new engine requirements of the ATCM.

(g) **Permanent Engine Replacements.** The permittee may install a new engine in place of a permitted E/S engine, fire water pump engine or engine used for an essential public service that breaks down and cannot be repaired, without first obtaining an ATC permit only if the requirements (i - v) listed herein are satisfied.

(i) The permitted stationary diesel IC engine is an E/S engine, a fire water pump engine or an engine used for an essential public service (as defined by the District).

(ii) The engine breaks down, cannot be repaired and needs to be replaced by a new engine.

(iii) The facility provides "good cause" (in writing) for the immediate need to install a permanent replacement engine prior to the time period before an ATC permit can be obtained for a new engine. The new engine must comply with the requirements of the ATCM for new engines. If a new engine is not immediately available, a temporary engine may be used while the new replacement engine is being procured. During this time period, the temporary replacement engine must meet the same guidelines and procedures as defined in the permit condition above (*Temporary Engine Replacements - DICE ATCM*).

(iv) An Authority to Construct application for the new permanent engine is submitted to the District within 15 days of the existing engine being replaced and the District permit for the new engine is obtained no later than 180 days from the date of engine replacement (these timelines include the use of a temporary engine).

(v) For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form may be sent hardcopy, or can be e-mailed (e-mail: engr@sbcapcd.org) to the District (Attn: Engineering Supervisor).

Any engine installed (either temporally or permanently) pursuant to this permit condition shall be immediately shut down if the District determines that the requirements of this condition have not been met.

(h) **Notification of Non-Compliance.** Owners or operators who have determined that they are operating their stationary diesel-fueled engine(s) in violation of the requirements specified in Sections (e)(1) or (e)(2) of the ATCM shall notify the District immediately upon detection of the violation and shall be subject to District enforcement action.

(i) **Notification of Loss of Exemption.** Owners or operators of in-use stationary diesel-fueled CI engines, who are subject to an exemption specified in Section (c) from all or part of the requirements of Section (e)(2) of the ATCM, shall notify the District immediately after they become aware that the exemption no longer applies and pursuant to Section (e)(4)(F)(1) of the ATCM shall demonstrate compliance within 180 days after notifying the District.

D.10 **Equipment Identification.** Identifying tag(s) or name plate(s) shall be displayed on the equipment to show manufacturer, model number, and serial number. The tag(s) or plate(s) shall be issued by the manufacturer and shall be affixed to the equipment in a permanent and conspicuous position

D.11 **Emission Factor Revisions.** The District may update the emission factors for any calculation based on USEPA AP-42 or District emission factors at the next permit modification or permit reevaluation to account for USEPA and/or District revisions to the underlying emission factors.

D.12 **CARB-Registered Portable Equipment.** State-registered portable equipment shall comply with State registration requirements. A copy of the State registration shall be readily available whenever the equipment is at the facility. [*Re: District Rule 202*]

D.13 **Abrasive Blasting Equipment.** All abrasive blasting activities performed on La Goleta facility shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530.

AIR POLLUTION CONTROL OFFICER

JUN 29 2012

Date

NOTES:

(A) This permit supersedes PT-70/Reeval 9584 R3, PTO 13479.
(B) Permit Reevaluation Due Date: June 2015
(C) Permit Expiration Date: June 2015

RECOMMENDATION:

It is recommended that this PTO be issued with the conditions as specified in the permit.

6/29/12 | 6-29-12

AQ Engineer | Engineering Supervisor

10.0 Attachments

10.1 Emission Calculation Documentation
10.2 Calculation Spreadsheets
10.3 Fee Calculations
10.4 IDS Database Emission Tables
10.5 Equipment List
10.6 Permittee Comments on the Draft Permit and the District Responses

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10.1 EMISSION CALCULATION DOCUMENTATION

This attachment contains all relevant emission calculation documentation used for the emission tables in Section 5. Refer to Section 4 for the general equations. The letters A through E below refer to Tables 5.1-1 and 5.1-2.

Reference A – Internal Combustion Engines

- The maximum operating schedule is in units of hours.
- The default fuel HHV is 1,050 Btu/scf.
- Emission factors (lb/MMBtu) are based on HHV.
- For conversion from ppmv to lb/MMBtu see section 10.2 calculations
- NO_x
  - ☞EF = 0.46 lb/MMBtu (lean-burn ICE);
  - ☞EF = 0.324 lb/MMBtu (rich burn ICEs), this EF is not based on the 50 ppmv exhaust concentration limit, it was established by the ERC agreement and is based on 90% reduction of uncontrolled emissions.
- CO
  - ☞EF = 10.125 lb/MMBtu (lean burn ICE);
  - ☞EF = 3.825 lb/MMBtu (rich burn ICEs)
- ROC
  - ☞EF = 2.495 lb/MMBtu (lean burn ICE);
  - ☞EF = 0.321 lb/MMBtu (rich burn ICEs)
- PM_{10}
  - ☞EF = 0.048 lb/MMBtu (lean burn ICE) USEPA AP-42 [Table 3.2-1 (7/00)];
  - ☞EF = 0.014 lb/MMBtu (rich burn ICEs) USEPA AP-42 [Table 3.2-3 (7/00)]
- SO_x
  - ☞ SO_x (as SO_2) = [0.169] × [ppmvd S ÷ (HHV of fuel]
  - ☞EF = 0.0129 lb/MMBtu
- Q (fuel use/time period) = (BSFC) * (bhp) * (hours/time period) / (HHV in Btu/scf)
- H (heat input / hour) = (Rated bhp) * (BSFC)

Eqpt.ID #	Plant ID#	IC Engine Description	Rated bhp	BSFC	MMBtu/hr Input
1199	# 2	I-R LVG-82; SN 8AL126	650	11,231	7.30
1200	# 3	I-R LVG-82; SN 8AL129	650	11,231	7.30
1201	# 4	I-R LVG-82; SN 8AL128	650	11,231	7.30
1202	# 5	I-R LVG 82; SN 8AL127	650	11,231	7.30
1203	# 6	I-R KVG-62; SN 6EL265	660	11,061	7.30
1204	# 7	I-R KVG-62; SN 6EL266	660	11,061	7.30
1205	# 8	I-R KVG-62; SN 6EL267	660	11,061	7.30
1206	# 9	Cooper-Bessemer GMV-10C	1100	9,109	10.02

HAP Emission Factors:

Hazardous air pollutant (HAP) emission factors for the IC engines are obtained from USEPA, Appendix A of the background report for Section 3.2 of AP-42. The database of source test results contained in appendix A can be downloaded from http://www.epa.gov/ttn/chief/ap42/ch03/related/c03s02.html. For MU 2-8, the average of all source test results in the database for each species for NSCR-controlled, four-cycle, rich-burn, IC engines at 90% load or greater was used as the emission factor. For MU 9, the average of all source test results for two stroke lean burn IC engines at 90% load or greater was used. For acrolein only source test reports based on FTIR were considered. The background report for Section 3.2 states that the EPA has identified possible interference problems with quantifying aldehyde emissions using CARB method 430 and recommends basing emission factors on FTIR measurements. For acetaldehyde and formaldehyde the source test results were non-detect, for these pollutants the emissions factors in this permit were based on the detection level of the source tests.

These emission factors are updated from permit reevaluation 9584-R2, which used emission factors from AP-42, Section 3.2 (January 1995).

GHG Emission Factors:

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For natural gas combustion the emission factor is:

(53.02 kg CO2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO2/MMBtu
(0.001 kg CH4/MMBtu) (2.2046 lb/kg)(21 lb CO2e/lb CH4) = 0.046 lb CO2e/MMBtu
(0.0001 kg N2O/MMBtu) (2.2046 lb/kg)(310 lb CO2e/lb N2O) = 0.068 lb CO2e/MMBtu
Total CO2e/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO2e/MMBtu

Reference B – 'C-60' Micro-turbines

- The maximum operating schedule is in units of hours.
- The default fuel HHV is 1,050 Btu/scf.
- Emission factors units (lb/MMBtu) are based on HHV.

- For conversion from lb/MW-hr to lb/MMBtu, *see section 10.2 calculations*

- NO_x
  - ☞EF = 0.5 lb/MW-hr
  - ☞EF = 0.0373 lb/MMBtu

- ROC
  - ☞EF = 1 lb/MW-hr
  - ☞EF = 0.0746 lb/MMBtu

- CO
  - ☞EF = 6 lb/MW-hr
  - ☞EF = 0.4478 lb/MMBtu

- PM_{10} emission factors, based on CA: DG-02 guidelines, are 0.0066 lb/MMBtu

- SO_x emissions based on mass balance:
  - ☞ SO_x (as SO_2) = [0.169] × [ppmvd S ÷ (HHV of fuel]
  - ☞EF = 0.0129 lb/MMBtu

- Q (fuel use/time period) = 12.8 scf/min

- H (MMBtu/hour) = Q (scf/min) * 60 (min/hour) * 1050 (Btu/scf) / 1,000,000

HAP Emission Factors:
Hazardous air pollutant (HAP) emission factors for the micro-turbines are obtained from USEPA, AP-42 Table 3.1-3 (April 2000). These factors are listed in Table 5.4-2A of this permit.

GHG Emission Factors:
GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually, then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For natural gas combustion the emission factor is:
(53.02 kg CO2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO2/MMBtu
(0.001 kg CH4/MMBtu) (2.2046 lb/kg)(21 lb CO2e/lb CH4) = 0.046 lb CO2e/MMBtu
(0.0001 kg N2O/MMBtu) (2.2046 lb/kg)(310 lb CO2e/lb N2O) = 0.068 lb CO2e/MMBtu
Total CO2e/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO2e/MMBtu

Reference C1 - Flares

☞ The maximum operating schedule is in units of hours

☞ The flare gas properties are:

⇒ HHV = 985 Btu/scf (estimated)

⇒ Fuel S = 80 ppmv (as total sulfur) for flare pilots and 239 ppmvd for flare gas

☞ The flare emission factors are based on Rule 359 limits for NO_x, ROC and CO

☞ SO_x emissions based on mass balance:

☞ SO_x (as SO_2) = [0.169] × [ppmvd S ÷ (HHV of fuel]

☞ EF = 0.041 lb/MMBtu

HAP Emission Factors:

Hazardous air pollutant (HAP) weight fractions for the flare emissions are obtained from *CARB Speciation Manual (2nd Edition, 9/91), Profile Number 79 (Flares – Chemical Manufacturing).* The speciation does not list methane or ethane, so the speciation does not need to be corrected from weight percent TOG to weight percent ROC.

GHG Emission Factors:

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually, then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For natural gas combustion the emission factor is:

(53.02 kg CO2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO2/MMBtu

(0.001 kg CH4/MMBtu) (2.2046 lb/kg)(21 lb CO2e/lb CH4) = 0.046 lb CO2e/MMBtu

(0.0001 kg N2O/MMBtu) (2.2046 lb/kg)(310 lb CO2e/lb N2O) = 0.068 lb CO2e/MMBtu

Total CO2e/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO2e/MMBtu

Reference C2 – Hot Oil Heaters

☞ The maximum operating schedule is in units of hours

☞ The emission factors for NO_x, CO, ROC, PM and PM_{10} are based on AP-42 emission factors for small natural gas-fired boilers (Tables 1.4-1 and 1.4-2 dated July 1998).

☞ SO_2 emission limits (factors) are based on the combustion of PUC natural gas.

HAP Emission Factors:

Hazardous air pollutant (HAP) emission factors for the hot oil heater emissions are obtained from AP-42 for small natural gas-fired boilers (Tables 1.4-3 dated July 1998).

GHG Emission Factors:

GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually, then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For natural gas combustion the emission factor is:

(53.02 kg CO2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO2/MMBtu

(0.001 kg CH4/MMBtu) (2.2046 lb/kg)(21 lb CO2e/lb CH4) = 0.046 lb CO2e/MMBtu

(0.0001 kg N2O/MMBtu) (2.2046 lb/kg)(310 lb CO2e/lb N2O) = 0.068 lb CO2e/MMBtu

Total CO2e/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO2e/MMBtu

Reference D – HC condensate Storage Tanks

- The maximum operating schedule is in units of hours;
- The hourly/daily/annual emissions scenario is based on the following assumptions:

- Hydrocarbon Condensate Tank:
  1. Maximum True vapor pressure: 5.5 psia @ 70°F
  2. API Gravity = 39
  3. Emissions occur 24 hours/day and 365 days/year.
  4. The annually-averaged HC throughput rate is 8.154 barrels/day corresponding to the annual throughput of 125,000 gallons/year

- Flotation Cells:
  1. Maximum True vapor pressure: 5.5 psia @ 70°F
  2. API Gravity = 39
  3. Emissions occur 24 hours/day and 365 days/year.
  4. The combined HC and brine water 'annual average' throughput rate is 48.924 barrels/day, corresponding to an annual throughput of 750,000 gallons for the entire facility.

- Emission factors are based on the *USEPA's AP-42, Section 7* guidelines.

  HAP Emission Factors:
  Hazardous air pollutant (HAP) weight fractions for the HC condensate storage tank emissions are obtained from the *CARB Speciation Manual (2nd Edition, 9/91), Profile Number 297(Crude Oil Evaporation)*. The weight fractions contained in the speciation manual are for total organic gases, therefore the weight fractions have been corrected to exclude methane and ethane. An example for benzene is given below:

  $\text{ROC fraction}_{\text{benzene}} = \text{TOG fraction}_{\text{benzene}} / (1 - \text{TOG fraction}_{\text{methane}} - \text{TOG fraction}_{\text{ethane}})$
  $\text{ROC fraction}_{\text{benzene}} = 0.0240 / (1\text{-}0.0880\text{-}0.0270) = 0.0240 / 0.8850 = 0.0271$

Reference E -- Loading Station

- The maximum operating schedule is in units of hours;
- The daily/annual emissions scenario is computed, based on the following assumptions:
  1. The liquid condensate loading rate occurs at a maximum rate of 7,140 gallons/hour, and 20,000 gallons/day (2.8 hours of operation) and 125,000 gal/year (17.51 hours of operation). The hourly loading rate and daily and annual hours of operation are not permit limits, they are just used to calculate daily and annual mass emissions.
  2. The loading at the NGL station is uncontrolled.
  3. The emission factors are derived from USEPA's AP-42, Chapter 5.2 (*Transportation and Marketing of Petroleum Liquids*) guidelines

$$L_L = 12.46 \frac{SPM}{T} \quad (1)$$

where:

L_L = loading loss, pounds per 1000 gallons (lb/10³ gal) of liquid loaded

S = a saturation factor (see Table 5.2-1)
P = true vapor pressure of liquid loaded, pounds per square inch absolute (psia) (see Figure 7.1-5, Figure 7.1-6, and Table 7.1-2)
M = molecular weight of vapors, pounds per pound-mole (lb/lb-mole) (see Table 7.1-2)
T = temperature of bulk liquid loaded, °R (°F + 460)

S = 0.60 (submerged loading, dedicated normal service)
P = 5.5 psia
M = 37 lb/lb-mol
T = 530 deg R

Loading loss THC emissions are then corrected to ROC using an ROC/THC ratio of 0.960.

<u>*HAP Emission Factors:*</u>
Hazardous air pollutant (HAP) weight fractions for the HC loading station emissions are obtained from the *CARB Speciation Manual (2nd Edition, 9/91), Profile Number 756 (Oil & Gas Production Fugitives – Liquid Service).* The weight fractions contained in the speciation manual are for total organic gases, therefore the weight fractions have been corrected to exclude methane and ethane. An example for benzene is given below:

ROC $\text{fraction}_{benzene}$ = TOG $\text{fraction}_{benzene}$ / (1 – TOG $\text{fraction}_{methane}$ – TOG fraction_{ethane})
ROC $\text{fraction}_{benzene}$ = 0.0010 /(1-0.0640-0.3760) = 0.0010 / 0.5600 = 0.0018

<u>Reference F - Gas Venting from Wells</u>

- The maximum operating schedule is in units of hours.

- All venting emissions are credited with zero percent emission control efficiency, since the venting operation is not subjected to any ROC emissions control.

- The specific volume of the PUC quality natural gas vented is 19.59 scf/lb. (9/14/99 data).

- Thus, each million standard cubic foot (MMscf) of gas vented at the facility weighs 10^6/19.59 = 51046.45 lbs.

- Field data (9/14/99) show the ROC mass fraction in the facility natural gas to be 13.3 percent.

- The ROC emission factor of the natural gas vented at the SoCalGas facility is, therefore, 51046.45 lbs.*0.133 = 6789 lb/MMscf.

- Assuming a methane weight fraction of 0.6130 (see HAP discussion), the methane content of each MMScf of gas is 51046.45 lb x 0.6130 = 31291.47 lb methane/MMscf

- The CO_{2e} emission factor for gas venting is 31291.47 lb CH_4/MMscf x 21 lb CO2e/lb CH_4 = 657,121 lb CO_{2e}/MMscf

<u>HAP Emission Factors</u>:

Hazardous air pollutant (HAP) emission factors for hexane are based on monthly gas composition analyses performed by SoCalGas for their PUC quality gas as well as the gas stored in their wells. Twenty-four data points were taken from the analytical results obtained during 2001 – 2002; these yielded a mean value of 0.05 for the 'hexane plus' fraction in the ROC. These analytical results were not reported as individual compounds, just as all compounds with the molecular weight of hexane or higher. Therefore the hexane emission factor listed in the tables is very conservative. The emission factor for benzene is based on the ROC content of the emissions, as speciated in *CARB Speciation Manual (2nd Edition, 9/91), Profile Number 757 (Oil & Gas Production Fugitives – Gas Service)*. The weight fraction for benzene contained in the speciation manual is a fraction of total organic gases, therefore the weight fraction has been corrected to exclude methane and ethane.

ROC $\text{fraction}_{\text{benzene}}$ = TOG $\text{fraction}_{\text{benzene}}$ / (1 – TOG $\text{fraction}_{\text{methane}}$ – TOG $\text{fraction}_{\text{ethane}}$)
ROC $\text{fraction}_{\text{benzene}}$ = 0.0010 /(1-0.6130-0.0790) = 0.0010 / 0.3080 = 0.0032

PTO 9584 R2 contained a column in the HAP tables for iso-octane (2,2,4 trimethylpentane). Iso-octane is a product of petroleum refining, since this facility receives and handles PUC quality natural gas, and the dehydration and separation processes at the facility do not include any refining, iso-octane is not expected in the gas handled at the facility.

SoCalGas has conducted sampling showing that iso-octane levels in the gas are non-detect. This sampling may also be used to further refine the emission factors for the other species.

<u>Reference G - Fugitive Components</u>

- The maximum operating schedule is in units of hours.

- All fugitive emission components are credited with zero percent emission control efficiency, since none of the equipment is subject to any fugitive emissions I&M program.

- The component leak path definition differs from the District Rule 331 definition of a component. A typical leak path count for a valve could be equal to 4 (one valve stem, a bonnet connection and two flanges).

- Leak path counts are provided by applicant and verified by facility inspections.

- Emission factors based on the District *P&P Document 6100.061.1996.* Production Field emission factors from Table 2 are used, but the ROC/THC ratio is 0.133, based on facility-specific data.

- Sample calculation spreadsheets are attached.

<u>HAP Emission Factors</u>:

Hazardous air pollutant (HAP) emission factors for hexane are based on monthly gas composition analyses performed by SoCalGas for their PUC quality gas as well as the gas stored in their wells. Twenty-four data points were taken from the analytical results obtained during 2001 – 2002; these yielded a mean value of 0.05 for the 'hexane plus' fraction in the ROC. These analytical results were not reported as individual compounds, just as all compounds with the molecular weight of hexane or higher. Therefore the hexane emission factor listed in the tables is very conservative. The emission factor for benzene is based on the ROC content of the emissions, as speciated in *CARB Speciation Manual (2nd Edition, 9/91), Profile Number 757 (Oil & Gas Production Fugitives – Gas Service)*. The weight fraction for benzene contained in the speciation manual is a fraction of total organic gases, therefore the weight fraction has been corrected to exclude methane and ethane.

$\text{ROC fraction}_{\text{benzene}} = \text{TOG fraction}_{\text{benzene}} / (1 - \text{TOG fraction}_{\text{methane}} - \text{TOG fraction}_{\text{ethane}})$
$\text{ROC fraction}_{\text{benzene}} = 0.0010 /(1\text{-}0.6130\text{-}0.0790) = 0.0010 / 0.3080 = 0.0032$

PTO 9584 R2 contained a column in the HAP tables for iso-octane (2,2,4 trimethylpentane). Iso-octane is a product of petroleum refining, since this facility receives and handles PUC quality natural gas, and the dehydration and separation processes at the facility do not include any refining, iso-octane is not expected in the gas handled at the facility.

SoCalGas has conducted sampling showing that iso-octane levels in the gas are non-detect. This sampling may also be used to further refine the emission factors for the other species.

Reference H - Solvents

- All solvents not used to thin surface coatings are included in this equipment category.

- Quarterly and annual ROC emission rates are based on estimated maximum solvent use (*see below*).

- Hourly emission limits are not provided; the facility operates 'JRI Model TL-21' parts washing unit using non-ROC solvents.'

- ROC emissions are estimated as: 2.20 lb/day and 0.4 ton/year; this is based on the estimated 'wipe cleaning' use of about 200 gallons of solvents per year containing about 800 lb of ROC.

- No District-approved solvent reclamation program operates at the facility.

HAP Emission Factors:
Hazardous air pollutant (HAP) emissions were not computed for 'solvent' emissions since a large number of solvents are used at the Plant, each solvent with a different HAP composition. Also, total ROC emissions from the solvents used do not exceed 0.4 ton *annually*; thus, the HAP fraction of the emissions are estimated to be below 0.05 tons on a conservative basis.

Reference I: Internal Combustion Engines – *District permit-exempt, Gas-fired engines*

- The maximum operating schedule is in units of hours.
- The default fuel (PUC quality natural gas) characteristics are:

☞ density = 0.0459lb/scf
☞ LHV = 950 Btu/scf
☞ HHV = 1,050 Btu/scf

- Emission factors units (lb/MMBtu) are based on HHV.

- LCF (conversion of LHV to HHV) values are not required to be used for fuel listed.

- *NO_x and ROC emission factors are consistent with those established for gas-fired, uncontrolled IC engines* — pursuant to a 1991 field study and agreed to by the District and the oil & gas industry in Santa Barbara, namely:

    - <u>NO_x</u>
      ☞$EF_{lb/MMBtu}$ = 1.905 (rich-burn ICE's: SCC # 20200202);

    - <u>ROC</u>
      ☞$EF_{lb/MMBtu}$ = 0.103 (rich-burn ICE's: SCC # 20200202)

    - CO emission factors are consistent with AP-42 , Section 3.2 Tables
    - For conversion from lb/MMscf to lb/MMBtu, used AP-42 (2/97) listed fuel HHV of 1019.4 Btu/scf
    - <u>CO</u>
      ☞$EF_{lb/MMBtu}$ = 1.6 (rich-burn ICE's; SCC # 20200253);

    - PM_{10} emission factors based on USEPA AP-42;
    - For rich-burn engines = 0.01275 lb/MMBtu [Table 3.2-4 (2/97)];
    - SO_x emissions based on mass balance:
      ☞ SO_x (as SO_2) = [0.169] × [ppmvd S ÷ (HHV of fuel]

<u>*HAP Emission Factors*</u>:

Hazardous air pollutant (HAP) emission factors for the gas-fired, uncontrolled, four-cycle, rich-burn, IC engines are obtained from USEPA, AP-42 (*Air-Chief as supplemented by FIRE, Version 9.0, October, 2001)*.

<u>*GHG Emission Factors:*</u>
GHG emissions from combustion sources are calculated using emission factors found in Tables C-1 and C-2 of 40 CFR Part 98 and global warming potentials found in Table A-1 of 40 CFR Part 98. CO2 equivalent emission factors are calculated for CO2, CH4, and N2O individually, then summed to calculate a total CO2e emission factor. Annual CO2e emission totals are presented in short tons.

For natural gas combustion the emission factor is:
(53.02 kg CO2/MMBtu) (2.2046 lb/kg) = 116.89 lb CO2/MMBtu
(0.001 kg CH4/MMBtu) (2.2046 lb/kg)(21 lb CO2e/lb CH4) = 0.046 lb CO2e/MMBtu

$(0.0001 \text{ kg } N_2O/\text{MMBtu})\ (2.2046 \text{ lb/kg})(310 \text{ lb } CO_2e/\text{lb } N_2O) = 0.068 \text{ lb } CO_2e/\text{MMBtu}$
Total CO_2e/MMBtu = 116.89 + 0.046 + 0.068 = 117.00 lb CO_2e/MMBtu

10.2 Calculation Spreadsheets

Combustion Equipment Emissions Calculations
ICE Emission Factor Derivation -- Conversion from ppmv to lb/MMBtu

ppmv to lb/MMBTU:

@ 15% exhaust oxygen (dry basis) & standard conditions (1.0 atm., 60 °F)

lb_i /MMBTU = $ppmv_i$ (SCF_i /$MMSCF_{exhaust}$) * (F, SCF $_{exhaust}$ /MMBTU) * (MW_i, lb_i /lb-mole) / (379 SCF_i /lb-mole) / (10^6/MM) / (XSA)

Acronym Description and Reference:

F	=	fuel expansion factor @ 0% excess exhaust oxygen, dry basis and 60 °F = 8608 scf/MMBtu (District ICE Technical Reference Document).
MW	=	Average molecular weight of exhaust pollutant specie(s), lb_i/lb-mole
XSA	=	Excess air correction factor from 0% to 15% exhaust oxygen {dimensionless constant = [20.9-15.0]/[20.9-0.0] = 0.282}.

Average Exhaust Pollutant Molecular Weights:

		lb_i/lb-mole
1.	NO_x as NO_2:	46
2.	CO	28
3.	ROC	41.31

The ROC molecular weight is an assumed average molecular weight for the non-methane, non-ethane organic compounds in the engine exhausts.

Combustion Equipment Emissions Calculations

Supplemental Information for Micro-turbines

TABLE 10.2 - EMISSION FACTOR DERIVATION FROM ARB DG-002

C60 Microturbines - PUC Quality Natural Gas

DATA:

Parameter	*Symbol*	*Value*	*Units*	*Reference*
Power Output	kW	60	kW	Permit application
Heat Rate (LHV based)	HRL	12,182	Btu/kWh	Permit application
Fuel Correction Factor	FCF	1.1	dimensionaless	Permit application
Heat Rate (HHV based)	HRH	13,400	Btu/kWh	Manufacturer Specifications
F-Factor (F_D)	FD	8,608	(dscf/MMBtu)	SBCAPCD ICE Tech Ref Doc
Molar Volume of Gasses	mv	379	(scf/lb-mole)	Attach. 5-5 USEPA Combustion Manual
Stack NOx (as NO2)	ppmvN	0.5	lb/MW-hr	Executive Order DG-002
Stack ROC (as CH4)	ppmvR	1	lb/MW-hr	Executive Order DG-002
Stack CO	ppmvC	6	lb/MW-hr	Executive Order DG-002
Molec Weight NOx	MWN	46	lb/lbmole	NOx as NO2
Molec Weight ROC	MWR	16	lb/lbmole	ROC as methane
Molec Weight CO	MWC	28	lb/lbmole	

CALCULATIONS:

Parameter	*Symbol*	*Value*	*Units*	*Calculation*
Hourly Heat Input	QH	0.804	MMBtu/hr	QH = (kW*HRH)/10^6
Stack Flow (0% O2)	S1	6,921	dscf/hr	S1 = FD * QH
Stack Flow (15% O2):	S2	24,516	dscf/hr	S2 = S1 * {(20.9-0)/(20.9-15)}
NOx Mass Emissions	EN	0.030	lb/hr	EN = {(ppmvN/10^6)*S2*MWN/mv}
ROC Mass Emissions	ER	0.060	lb/hr	ER = {(ppmvR/10^6)*S2*MWR/mv}
CO Mass Emissions	EC	0.360	lb/hr	EC = {(ppmvC/10^6)*S2*MWC/mv}
NOx Emission Factor	EFNOX	0.0373	lb/MMBtu	EFNOX = EN/QH
ROC Emission Factor	EFROC	0.0746	lb/MMBtu	EFROC = ER/QH
CO Emission Factor	EFCO	0.4478	lb/MMBtu	EFCO = EC/QH
Stack NOx (as NO2)	ppmvN	10	ppmv	ppmvN = {(EN*{mv/MWN}*(10^6/S2)}
Stack ROC (as CH4)	ppmvR	58	ppmv	ppmvR = {(ER*{mv/MWR}*(10^6/S2)}
Stack CO	ppmvC	199	ppmv	ppmvC = {(EC*{mv/MWC}*(10^6/S2)}

FIXED ROOF TANK CALCULATION (AP-42: Chapter 7 Method)

Basic Input Data	
liquid (1:G13, 2:G10, 3:G7, 4:C, 5:JP, 6:ker, 7:O2, 8:O6) =	4
liquid TVP =	5.5
if TVP is entered, enter TVP temperature (°F) =	70
tank heated (yes, no) =	no
if tank is heated, enter temp (°F) =	
vapor recovery system present? (yes, no) =	yes
is this a wash tank? (yes, no) =	no
will flashing losses occur in this tank? (yes, no) =	no
breather vent pressure setting range (psi) (def = 0.06):	0.06

Attachment:	10.2
Permit:	ATC/PTO10980
Date:	01/27/09
Tank:	Flotation-1
Name:	SoCalGas
Filename:	..\flot-tank1-calc.xls
District:	Santa Barbara
Version:	Tank-2c.xls

PRINT

ATC PROPOSED EMISSIONS

Tank Data		
diameter (feet) =		12
capacity (enter barrels in first col, gals will compute) =	238	10,000
conical or dome roof? (c, d) =		c
shell height (feet) =		12
roof height (def = 1):		1
ave liq height (feet):		6
color (1:Spec Al, 2:Diff Al, 3:Lite, 4:Med, 5:Rd, 6:Wh) =		4
condition (1: Good, 2: Poor) =		1

Paint Factor Matrix		
	paint condition	
paint color	good	poor
spec alum	0.39	0.49
diff alum	0.60	0.68
lite grey	0.54	0.63
med grey	0.68	0.74
red	0.89	0.91
white	0.17	0.34

Molecular Weight Matrix	
liquid	mol wt
gas rvp 13	62
gas rvp 10	66
gas rvp 7	68
crude oil	50
JP-4	80
jet kerosene	130
fuel oil 2	130
fuel oil 6	190

Liquid Data	A	B
maximum daily throughput (bopd) =		49
Ann thruput (gal): (enter value in Column A if not max PTE)		7.500E+05
RVP (psia):		7.0119
°API gravity =		39

Computed Values		
root outage [1] (feet):		0.3
vapor space volume [2] (cubic feet):		713
turnovers [3]:		75
turnover factor [4]:		0.57
paint factor [5]:		0.68
surface temperatures (°R, °F)		
average [6]:	527.2	67.2
maximum [7]:	539	79
minimum [8]:	515.4	55.4
product factor [9]:		0.75
diurnal vapor ranges		
temperature [10] (fahrenheit degrees):		47.2
vapor pressure [11] (psia):		2.175608
molecular weight [12] (lb/lb-mol):		50
TVP [13] (psia) [adjusted for ave liquid surface temp]:		5.23685
vapor density [14] (lb/cubic foot):		0.046283
vapor expansion factor [15]:		0.313
vapor saturation factor [16]:		0.363824
vented vapor volume (scf/bbl):		13.3
fraction ROG - flashing losses:		0.308
fraction ROG - evaporative losses:		0.885

Adjusted TVP Matrix	
liquid	TVP value
gas rvp 13	7.908
gas rvp 10	5.56
gas rvp 7	3.932
crude oil	5.23685
JP-4	1.516
jet kerosene	0.0103
fuel oil 2	0.009488
fuel oil 6	0.0000472

RVP Matrix	
liquid	RVP value
gas rvp 13	13
gas rvp 10	10
gas rvp 7	7
crude oil	7.011897
JP-4	2.7
jet kerosene	0.029
fuel oil 2	0.022
fuel oil 6	0.00019

Long-Term VRU_Eff = 95.00%

Short-Term VRU_Eff = 95.00%

Emissions	Uncontrolled ROC emissions			Controlled ROC emissions		
	lb/hr	lb/day	ton/year	lb/hr	lb/day	ton/year
breathing loss [17] =	0.14	3.33	0.61	0.01	0.17	0.03
working loss [18] =	0.20	4.85	0.88	0.01	0.24	0.04
flashing loss [19] =	0.00	0.00	0.00	0.00	0.00	0.00
TOTALS =	**0.34**	**8.17**	**1.49**	**0.02**	**0.41**	**0.07**

FIXED ROOF TANK CALCULATION (AP-42: Chapter 7 Method)

Basic Input Data	
liquid (1:G13, 2:G10, 3:G7, 4:C, 5:JP, 6:ker, 7:O2, 8:O6) =	4
liquid TVP =	5.5
if TVP is entered, enter TVP temperature (°F) =	70
tank heated (yes, no) =	no
if tank is heated, enter temp (°F) =	
vapor recovery system present? (yes, no) =	yes
is this a wash tank? (yes, no) =	no
will flashing losses occur in this tank? (yes, no) =	no
breather vent pressure setting range (psi) (def = 0.06):	0.06

Attachment:	10.2
Permit:	ATC/PTO 10980
Date:	01/27/09
Tank:	HC storage tank
Name:	SoCalGas
Filename:	...\HC-tank-calc.xls
District:	Santa Barbara
Version:	Tank-2c.xls

PRINT

Tank Data		
diameter (feet) =		10
capacity (enter barrels in first col, gals will compute) =	168	7,050
conical or dome roof? (c, d) =		c
shell height (feet) =		12
roof height (def = 1):		1
ave liq height (feet):		6
color (1:Spec Al, 2:Diff Al, 3:Lite, 4:Med, 5:Rd, 6:Wh) =		4
condition (1: Good, 2: Poor) =		1

ATC' PROPOSED EMISSIONS

Paint Factor Matrix		
	paint condition	
paint color	good	poor
spec alum	0.39	0.49
diff alum	0.60	0.68
lite grey	0.54	0.63
med grey	0.68	0.74
red	0.89	0.91
white	0.17	0.34

Molecular Weight Matrix	
liquid	mol wt
gas rvp 13	62
gas rvp 10	66
gas rvp 7	68
crude oil	50
JP-4	80
jet kerosene	130
fuel oil 2	130
fuel oil 6	190

Liquid Data	A	B
maximum daily throughput (bopd) =		8
Ann thruput (gal): (enter value in Column A if not max PTE)		1.250E+05
RVP (psia):		7.0119
°API gravity =		39

Computed Values		
roof outage [1] (feet):		0.3
vapor space volume [2] (cubic feet):		495
turnovers [3]:		17.73
turnover factor [4]:		1
paint factor [5]:		0.68
surface temperatures (°R, °F)		
average [6]:	527.2	67.2
maximum [7]:	539	79
minimum [8]:	515.4	55.4
product factor [9]:		0.75
diurnal vapor ranges		
temperature [10] (fahrenheit degrees):		47.2
vapor pressure [11] (psia):		2.175608
molecular weight [12] (lb/lb-mol):		50
TVP [13] (psia) [adjusted for ave liquid surface temp]:		5.23685
vapor density [14] (lb/cubic foot):		0.046283
vapor expansion factor [15]:		0.313
vapor saturation factor [16]:		0.363824
vented vapor volume (scf/bbl):		13.3
fraction ROG - flashing losses:		0.308
fraction ROG - evaporative losses:		0.885

Adjusted TVP Matrix	
liquid	TVP value
gas rvp 13	7.908
gas rvp 10	5.56
gas rvp 7	3.932
crude oil	5.23685
JP-4	1.516
jet kerosene	0.0103
fuel oil 2	0.009488
fuel oil 6	0.0000472

RVP Matrix	
liquid	RVP value
gas rvp 13	13
gas rvp 10	10
gas rvp 7	7
crude oil	7.011897
JP-4	2.7
jet kerosene	0.029
fuel oil 2	0.022
fuel oil 6	0.00019

Long-Term VRU_Eff = 95.00%

Short-Term VRU_Eff = 95.00%

Emissions	Uncontrolled ROC emissions			Controlled ROC emissions		
	lb/hr	lb/day	ton/year	lb/hr	lb/day	ton/year
breathing loss [17] =	0.10	2.31	0.42	0.00	0.12	0.02
working loss [18] =	0.06	1.42	0.26	0.00	0.07	0.01
flashing loss [19] =	0.00	0.00	0.00	0.00	0.00	0.00
TOTALS =	**0.16**	**3.73**	**0.68**	**0.01**	**0.19**	**0.03**

10.3 Fee Calculations

Emission fees for the La Goleta facility are based on District Rule 210, Section I.B.1, Schedule A (July, 2011). Since the last permit was issued in June 2009 and this PTO is being issued in June 2012, no pro-rating of the fees is necessary. The fee Table is shown next.

FEE STATEMENT

PT-70/Reeval No. 09584 - R4
FID: 01734 La Goleta / SSID: 05019

Santa Barbara County
Air Pollution Control District

Device Fee

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
001199	IC Engine: Gas Compressor # 2	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001200	IC Engine: Gas Compressor # 3	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001201	IC Engine: Gas Compressor # 4	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001202	IC Engine: Gas Compressor # 5	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001203	IC Engine: Gas Compressor # 6	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001204	IC Engine: Gas Compressor # 7	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001205	IC Engine: Gas Compressor # 8	A3	7.300	461.88	Per 1 million Btu input	No	1	1.000	3,371.72	0.00	0.00	3,371.72
001206	IC Engine: Gas Compressor # 9	A3	10.020	461.88	Per 1 million Btu input	No	1	1.000	4,628.04	0.00	0.00	4,628.04
107543	Micro-turbine Generator, Unit 1	A3	0.804	461.88	Per 1 million Btu input	No	1	1.000	371.35	0.00	0.00	371.35
107544	Micro-turbine Generator, Unit 2	A3	0.804	461.88	Per 1 million Btu input	No	1	1.000	371.35	0.00	0.00	371.35
107545	Micro-turbine Generator, Unit 3	A3	0.804	461.88	Per 1 million Btu input	No	1	1.000	371.35	0.00	0.00	371.35
107546	Micro-turbine Generator, Unit 4	A3	0.804	461.88	Per 1 million Btu input	No	1	1.000	371.35	0.00	0.00	371.35
008666	E/S Diesel Firewater Pump # 12A	A3	0.930	461.88	Per 1 million Btu input	No	1	1.000	429.55	0.00	0.00	429.55
008668	E/S Diesel Firewater Pump # 13A	A3	0.930	461.88	Per 1 million Btu input	No	1	1.000	429.55	0.00	0.00	429.55
113418	Sulfides Scrubber Unit	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
001215	Flare #3 (Tank Farm)	A3	1.600	461.88	Per 1 million Btu input	No	1	1.000	739.01	0.00	0.00	739.01

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
001212	Flare #2 (Plant #14)	A3	1.600	461.88	Per 1 million Btu input	No	1	1.000	739.01	0.00	0.00	739.01
001211	Flare #1 (Plant #14)	A3	1.600	461.88	Per 1 million Btu input	No	1	1.000	739.01	0.00	0.00	739.01
104915	Sulfides Scrubber Units	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
104916	Reduced Sulfur Scrubber Unit	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
107706	Reduced Sulfur Scrubber Unit	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
001214	Hot Oil Heater #1	A3	4.000	461.88	Per 1 million Btu input	No	1	1.000	1,847.52	0.00	0.00	1,847.52
107535	Hot Oil Heater #2	A3	2.200	461.88	Per 1 million Btu input	No	1	1.000	1,016.14	0.00	0.00	1,016.14
001219	Flotation Cell #1	A6	10.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
001220	Flotation Cell #2	A6	10.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
001217	Liquid Hydrocarbon Storage Tank	A6	7.050	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
001218	Brine Water Storage Tank	A6	40.600	3.53	Per 1000 gallons	No	1	1.000	143.32	0.00	0.00	143.32
100899	Methanol Storage Tank	A6	0.500	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
100901	Odorant Storage Tank	A6	1.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
100873	Gas/Glycol Contactors	A6	1.000	3.53	Per 1000 gallons	Min	3	1.000	183.51	0.00	0.00	183.51
113417	Glycol Particulate Filters	A1.a	2.000	61.57	Per equipment	No	2	1.000	246.28	0.00	0.00	246.28
100874	Gas/Glycol Contactor	A6	1.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
100878	Glycol/Gas Separator	A6	1.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
100889	Glycol Rectifier	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100892	Electric Motors Driving Glycol Rectifier Pumps	A2	5.000	31.92	Per total rated hp	No	2	1.000	319.20	0.00	0.00	319.20
100893	Electric Motors Driving Glycol Pumps	A2	20.000	31.92	Per total rated hp	No	3	1.000	1,915.20	0.00	0.00	1,915.20
100875	Vapor Condensing Coils	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100879	High Pressure Separator	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100880	Sand Trap	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100881	Low Pressure Separator	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100887	Condensate Surge Tank	A6	1.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
100888	Horizontal Separator	A6	1.000	3.53	Per 1000 gallons	Min	1	1.000	61.17	0.00	0.00	61.17
100894	Vapor Condensing Coils	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100895	High Pressure Separator	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100896	Low Pressure Separator	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100866	Cooling Motor Fan in Heat Exchanger	A2	40.000	31.92	Per total rated hp	No	1	1.000	1,276.80	0.00	0.00	1,276.80
100867	Cooling Motor Fan in Heat Exchanger	A2	40.000	31.92	Per total rated hp	No	1	1.000	1,276.80	0.00	0.00	1,276.80
100865	Cooling Motor Fan in Heat Exchanger	A2	40.000	31.92	Per total rated hp	No	1	1.000	1,276.80	0.00	0.00	1,276.80
100868	Oil Heater Circulation Pump Motors	A2	40.000	31.92	Per total rated hp	No	1	1.000	1,276.80	0.00	0.00	1,276.80
100869	Glycol Unit Condenser Fan Motor	A2	6.000	31.92	Per total rated hp	No	1	1.000	191.52	0.00	0.00	191.52
113420	Odorant Expansion Tanks	A1.a	1.000	61.57	Per equipment	No	2	1.000	123.14	0.00	0.00	123.14
100870	Glycol Unit Condenser Fan Motor	A2	5.000	31.92	Per total rated hp	No	1	1.000	159.60	0.00	0.00	159.60
100872	Oil Heater Blower Fan	A2	7.500	31.92	Per total rated hp	No	1	1.000	239.40	0.00	0.00	239.40
107541	Oil Heater Blower Fan, New	A2	1.000	31.92	Per total rated hp	Min	1	1.000	61.17	0.00	0.00	61.17
008670	Underground Gas Storage Wells	A1.a	1.000	61.57	Per equipment	No	21	1.000	1,292.97	0.00	0.00	1,292.97
100876	Accumulator Stack	A1.a	1.000	61.57	Per equipment	No	2	1.000	123.14	0.00	0.00	123.14
100897	Blower	A2	1.500	31.92	Per total rated hp	Min	1	1.000	61.17	0.00	0.00	61.17
008669	Grade Level Loading Station	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100903	Gas Stacks/Vents	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
100898	Condensate Pump	A2	5.000	31.92	Per total rated hp	No	1	1.000	159.60	0.00	0.00	159.60
100900	Pneumatic Pumps	A1.a	1.000	61.57	Per equipment	No	2	1.000	123.14	0.00	0.00	123.14
100904	Vent Stack Sump Pump	A1.a	1.000	61.57	Per equipment	No	1	1.000	61.57	0.00	0.00	61.57
113419	Odorant Metering Pumps	A1.a	2.000	61.57	Per equipment	No	2	1.000	246.28	0.00	0.00	246.28
100871	Condensate Pumps	A2	1.500	31.92	Per total rated hp	Min	1	1.000	61.17	0.00	0.00	61.17
	Device Fee Sub-Totals =								**$47,886.38**	**$0.00**	**$0.00**	
	Device Fee Total =											**$47,886.38**

Permit Fee

Fee Based on Devices	**47,886.38**

Fee Statement Grand Total = $47,886

Notes:

(1) Fee Schedule Items are listed in District Rule 210, Fee Schedule "A".
(2) The term "Units" refers to the unit of measure defined in the Fee Schedule.

10.4 IDS Database Emission Tables

Table 10.4-1
Permitted Potential to Emit (PPTE)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
Part 70/District PTO 9584-R4 – La Goleta Plant						
lb/day	551.73	1658.33	7184.68	26.49	32.27	32.27
tons/year	97.76	292.54	1,310.58	4.85	5.70	5.70

Table 10.4-2
Facility Potential to Emit (FPTE)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
Part 70/District PTO 9584-R4 – La Goleta Plant						
lb/day	551.73	1658.33	7184.68	26.49	32.27	32.27
tons/year	97.76	292.54	1,310.58	4.85	5.70	5.70

Table 10.4-3
Facility 'Federal" Potential to Emit

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
Part 70/District PTO 9584-R4 – La Goleta Plant						
lb/day	597.45	1,300.58	7,223.08	26.80	32.61	32.61
tons/year	106.11	227.25	1,317.58	4.91	5.76	5.76

Table 10.4-4
Facility Net Emission Increase Since 1990 (FNEI-90)

	NO_X	ROC	CO	SO_X	TSP	PM_{10}
Part 70/District PTO 9584-R4 – La Goleta Plant						
lb/day	1.77	4.22	0.00	1.03	0.30	0.30
tons/year	0.33	0.86	0.00	0.19	0.05	0.05

10.5 Equipment List

A PERMITTED EQUIPMENT

1 IC Engines with Controlled Emissions

1.1 IC Engine: Gas Compressor # 2

Device ID #	**001199**	*Device Name*	**IC Engine: Gas Compressor # 2**
Rated Heat Input		*Physical Size*	650.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 2
Model	LVG-82,	*Serial Number*	8AL126
Location Note			
Device Description			

1.2 IC Engine: Gas Compressor # 3

Device ID #	**001200**	*Device Name*	**IC Engine: Gas Compressor # 3**
Rated Heat Input		*Physical Size*	650.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 3
Model	LVG-82	*Serial Number*	8AL129
Location Note			
Device Description			

1.3 IC Engine: Gas Compressor # 4

Device ID #	**001201**	*Device Name*	**IC Engine: Gas Compressor # 4**
Rated Heat Input		*Physical Size*	650.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 4
Model	LVG-82	*Serial Number*	8AL128
Location Note			
Device Description			

1.4 IC Engine: Gas Compressor # 5

Device ID #	**001202**	***Device Name***	**IC Engine: Gas Compressor # 5**
Rated Heat Input		*Physical Size*	650.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 5
Model	LVG-82	*Serial Number*	8AL127
Location Note			
Device Description			

1.5 Catalytic Converter #2

Device ID #	**110814**	***Device Name***	**Catalytic Converter #2**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#2
Model	DC74	*Serial Number*	164728
Location Note			
Device Description			

1.6 Catalytic Converter #3

Device ID #	**110815**	***Device Name***	**Catalytic Converter #3**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#3
Model	DC74	*Serial Number*	164729
Location Note			
Device Description			

1.7 Catalytic Converter #4

Device ID #	**110816**	***Device Name***	**Catalytic Converter #4**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#4
Model	DC74	*Serial Number*	164724
Location Note			
Device Description			

1.8 Catalytic Converter #5

Device ID #	**110817**	***Device Name***	**Catalytic Converter #5**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#5
Model	DC74	*Serial Number*	164723
Location Note			
Device Description			

1.9 Catalytic Converter #6

Device ID #	**110818**	***Device Name***	**Catalytic Converter #6**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#6
Model	DC74	*Serial Number*	164727
Location Note			
Device Description			

1.10 Catalytic Converter #7

Device ID #	**110819**	***Device Name***	**Catalytic Converter #7**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#7
Model	DC74	*Serial Number*	164725
Location Note			
Device Description			

1.11 Catalytic Converter #8

Device ID #	**110820**	***Device Name***	**Catalytic Converter #8**
Rated Heat Input		*Physical Size*	
Manufacturer	DCL International	*Operator ID*	#8
Model	DC74	*Serial Number*	164726
Location Note			
Device Description			

1.12 IC Engine: Gas Compressor # 6

Device ID #	**001203**	***Device Name***	**IC Engine: Gas Compressor # 6**
Rated Heat Input		*Physical Size*	660.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 6
Model	KVG-62	*Serial Number*	6EL265
Location Note			
Device Description			

1.13 IC Engine: Gas Compressor # 7

Device ID #	**001204**	***Device Name***	**IC Engine: Gas Compressor # 7**
Rated Heat Input		*Physical Size*	660.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 7
Model	KVG-62	*Serial Number*	6EL266
Location Note			
Device Description			

1.14 IC Engine: Gas Compressor # 8

Device ID #	**001205**	***Device Name***	**IC Engine: Gas Compressor # 8**
Rated Heat Input		*Physical Size*	660.00 Horsepower
Manufacturer	Ingersoll-Rand	*Operator ID*	Gas Compressor # 8
Model	KVG-62	*Serial Number*	6EL267
Location Note			
Device Description			

1.15 IC Engine: Gas Compressor # 9

Device ID #	**001206**	***Device Name***	**IC Engine: Gas Compressor # 9**
Rated Heat Input		*Physical Size*	1100.00 Horsepower
Manufacturer	Cooper-Bessemer	*Operator ID*	Gas Compressor # 9
Model	GMV-10C	*Serial Number*	
Location Note			
Device Description			

1.16 Micro-turbine Generator, Unit 1

Device ID #	**107543**	*Device Name*	**Micro-turbine Generator, Unit 1**
Rated Heat Input	0.804 MMBtu/Hour	*Physical Size*	
Manufacturer	Capstone	*Operator ID*	#1
Model	C-60	*Serial Number*	
Location Note			
Device Description	NG-fired unit.		

1.17 Micro-turbine Generator, Unit 2

Device ID #	**107544**	*Device Name*	**Micro-turbine Generator, Unit 2**
Rated Heat Input	0.804 MMBtu/Hour	*Physical Size*	
Manufacturer	Capstone	*Operator ID*	# 2
Model	C-60	*Serial Number*	
Location Note			
Device Description	NG-fired unit		

1.18 Micro-turbine Generator, Unit 3

Device ID #	**107545**	*Device Name*	**Micro-turbine Generator, Unit 3**
Rated Heat Input	0.804 MMBtu/Hour	*Physical Size*	
Manufacturer	Capstone	*Operator ID*	# 3
Model	C-60	*Serial Number*	
Location Note			
Device Description	NG-fired unit		

1.19 Micro-turbine Generator, Unit 4

Device ID #	**107546**	*Device Name*	**Micro-turbine Generator, Unit 4**
Rated Heat Input	0.804 MMBtu/Hour	*Physical Size*	
Manufacturer	Capstone	*Operator ID*	# 4
Model	C-60	*Serial Number*	
Location Note			
Device Description	NG-fired unit		

1.20 E/S Diesel Firewater Pump # 12A

Device ID #	008666	*Maximum Rated BHP*	133.00
Device Name	E/S Diesel Firewater Pump # 12A	*Serial Number*	20195869
Engine Use	Firewater Pump	*EPA Engine Family Name*	--
Manufacturer	Cummins	*Operator ID*	# 12A
Model Year	--	*Fuel Type*	CARB Diesel
Model	V-378-F2		
DRP/ISC?	No	*Healthcare Facility?*	No
Daily Hours	2	*Annual Hours*	20
Location Note			
Device Description			

1.21 E/S Diesel Firewater Pump # 13A

Device ID #	008668	*Maximum Rated BHP*	133.00
Device Name	E/S Diesel Firewater Pump # 13A	*Serial Number*	20195868
Engine Use	Firewater Pump	*EPA Engine Family Name*	--
Manufacturer	Cummins	*Operator ID*	# 13A
Model Year	--	*Fuel Type*	CARB Diesel
Model	V-378-F2		
DRP/ISC?	No	*Healthcare Facility?*	No
Daily Hours	2	*Annual Hours*	20
Location Note			
Device Description			

2 Flares

2.1 Flare #3 (Tank Farm)

Device ID #	**001215**	***Device Name***	**Flare #3 (Tank Farm)**
Rated Heat Input	1.600 MMBtu/Hour	*Physical Size*	
Manufacturer		*Operator ID*	#3
Model		*Serial Number*	
Location Note			
Device Description	Pilot w/ natural gas.		

2.2 Flare #2 (Plant #14)

Device ID #	**001212**	*Device Name*	**Flare #2 (Plant #14)**
Rated Heat Input	1.600 MMBtu/Hour	*Physical Size*	
Manufacturer		*Operator ID*	#2
Model		*Serial Number*	
Location Note			
Device Description	Pilot w/ natural gas.		

2.3 Flare #1 (Plant #14)

Device ID #	**001211**	*Device Name*	**Flare #1 (Plant #14)**
Rated Heat Input	1.600 MMBtu/Hour	*Physical Size*	
Manufacturer		*Operator ID*	#1
Model		*Serial Number*	
Location Note			
Device Description	Pilot w/ natural gas.		

2.4 Flare Gas Sulfur Removal Units

2.4.1 Sulfides Scrubber Units

Device ID #	**104915**	*Device Name*	**Sulfides Scrubber Units**
Rated Heat Input		*Physical Size*	
Manufacturer	Cameron	*Operator ID*	
Model	SULFATREAT	*Serial Number*	
Location Note	Before the glycol exhaust flare unit		
Device Description	Hydrogen Sulfide scrubber unit, 46" dia by 88" high, 4950 lbs. bed weight		

2.4.2 Sulfides Scrubber Unit

Device ID #	**113418**	*Device Name*	**Sulfides Scrubber Unit**
Rated Heat Input		*Physical Size*	
Manufacturer	Cameron	*Operator ID*	
Model	SULFATREAT	*Serial Number*	
Location Note			
Device Description	Hydrogen Sulfide scrubber unit, 46" dia by 88" high, 4950 lb		

2.4.3 Reduced Sulfur Scrubber Unit

Device ID #	**104916**	*Device Name*	**Reduced Sulfur Scrubber Unit**
Rated Heat Input		*Physical Size*	
Manufacturer	Cameron	*Operator ID*	
Model	CEI-KMN	*Serial Number*	
Location Note	before the glycol exhaust flare unit		
Device Description	TRS Removal Unit B, 46" dia by 64" high; bed size 2850 lbs.		

2.4.4 Reduced Sulfur Scrubber Unit

Device ID #	**107706**	*Device Name*	**Reduced Sulfur Scrubber Unit**
Rated Heat Input		*Physical Size*	
Manufacturer	Cameron	*Operator ID*	
Model	CEI-KMN	*Serial Number*	
Location Note			
Device Description	TRS Removal Unit C, 46" dia by 64" high; bed size 2850 lbs.		

3 External Combustion Units

3.1 Hot Oil Heater #1

Device ID #	**001214**	*Device Name*	**Hot Oil Heater #1**
Rated Heat Input	3.500 MMBtu/Hour	*Physical Size*	
Manufacturer	Fulton Thermal Corporation	*Operator ID*	HOH #1
Model	FT-0400C	*Serial Number*	2788C
Location Note			
Device Description			

3.2 Hot Oil Heater #2

Device ID #	**107535**	*Device Name*	**Hot Oil Heater #2**
Rated Heat Input	2.200 MMBtu/Hour	*Physical Size*	
Manufacturer	American Heating Company	*Operator ID*	HOH #2
Model	AHE-212-2P	*Serial Number*	670-A04
Location Note			
Device Description	Gas-fired unit. Operates only when HOH #1 is not operating.		

4 Fixed Roof Tanks

4.1 Flotation Cell #1

Device ID #	**001219**	*Device Name*	**Flotation Cell #1**
Rated Heat Input		*Physical Size*	10000.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	12' dia. by 12' height.		

4.2 Flotation Cell #2

Device ID #	**001220**	*Device Name*	**Flotation Cell #2**
Rated Heat Input		*Physical Size*	10000.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	12' dia. by 12' height.		

4.3 Liquid Hydrocarbon Storage Tank

Device ID #	**001217**	*Device Name*	**Liquid Hydrocarbon Storage Tank**
Rated Heat Input		*Physical Size*	7050.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	10' dia. by 12' height.		

4.4 Condensate Surge Tank

Device ID #	**100887**	*Device Name*	**Condensate Surge Tank**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	3' dia by 32' tall.		

4.5 Odorant Expansion Tanks

Device ID #	**113420**	*Device Name*	**Odorant Expansion Tanks**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	10" by 13", serving the odorant metering system. Controlled by a 55 gallon carbon canister.		

4.6 Brine Water Storage Tank

Device ID #	**001218**	*Device Name*	**Brine Water Storage Tank**
Rated Heat Input		*Physical Size*	40600.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	24' dia. by 12' height.		

4.7 Methanol Storage Tank

Device ID #	**100899**	*Device Name*	**Methanol Storage Tank**
Rated Heat Input		*Physical Size*	500.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Pressurized with natural gas; with pressure relief valve.		

4.8 Odorant Storage Tank

Device ID #	**100901**	*Device Name*	**Odorant Storage Tank**
Rated Heat Input		*Physical Size*	1000.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Relief valve set @ 33 psig, odorant -- Captan 50/Thiophane.		

5 Fugitive Hydrocarbon Components - Gas/LightLiquid Svc - CLP

5.1 Valves - Accessible

Device ID #	**100882**	*Device Name*	**Valves - Accessible**
Rated Heat Input		*Physical Size*	2641.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

5.2 Connections - Accessible

Device ID #	**100883**	*Device Name*	**Connections - Accessible**
Rated Heat Input		*Physical Size*	18339.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

5.3 Pressure Relief Devices - Uncontrolled

Device ID #	**100886**	*Device Name*	**Pressure Relief Devices - Uncontrolled**
Rated Heat Input		*Physical Size*	91.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

5.4 Compressor Seals - Accessible

Device ID #	**100885**	*Device Name*	**Compressor Seals - Accessible**
Rated Heat Input		*Physical Size*	17.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

5.5 Pump Seals - Accessible

Device ID #	**100884**	*Device Name*	**Pump Seals - Accessible**
Rated Heat Input		*Physical Size*	2.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

6 Glycol Dehydration Unit

6.1 Gas/Glycol Contactors

Device ID #	**100873**	*Device Name*	**Gas/Glycol Contactors**
Rated Heat Input		*Physical Size*	
Manufacturer	Braun & Lacy	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Three (3) units each 4.5' dia. by 37.8' long; with three (3) control tanks, each 16" dia. by 15.25' long.		

6.2 Glycol Particulate Filters

Device ID #	**113417**	*Device Name*	**Glycol Particulate Filters**
Rated Heat Input		*Physical Size*	
Manufacturer	Eaton Corporation	*Operator ID*	F-GL3A and F-GL3B
Model	MBF 0402	*Serial Number*	
Location Note			
Device Description	1.83' dia by 3.04' tall, replace two Rol-Pak filters (Device ID 100877)		

6.3 Gas/Glycol Contactor

Device ID #	**100874**	*Device Name*	**Gas/Glycol Contactor**
Rated Heat Input		*Physical Size*	
Manufacturer	Braun & Lacy	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	One (1) unit 4.5' dia. by 38.9' long; with a control tank 16" dia. by 17.67' long.		

6.4 Glycol/Gas Separator

Device ID #	**100878**	*Device Name*	**Glycol/Gas Separator**
Rated Heat Input		*Physical Size*	
Manufacturer	Southwest Welding	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	4' dia. by 10.2' tall.		

6.5 Glycol Rectifier

Device ID #	**100889**	*Device Name*	**Glycol Rectifier**
Rated Heat Input		*Physical Size*	
Manufacturer	Fisher-Klosterman	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	18" diameter.		

6.6 Electric Motors Driving Glycol Rectifier Pumps

Device ID #	**100892**	*Device Name*	**Electric Motors Driving Glycol Rectifier Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Rated at 5 hp each.		

6.7 Electric Motors Driving Glycol Pumps

Device ID #	**100893**	*Device Name*	**Electric Motors Driving Glycol Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Rated at 20 hp each.		

7 Solvent Cleaning and Usage

7.1 Solvent Usage

Device ID #	**008680**	*Device Name*	**Solvent Usage**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

8 Separator Units in Processes

8.1 Vapor Condensing Coils

Device ID #	**100875**	*Device Name*	**Vapor Condensing Coils**
Rated Heat Input		*Physical Size*	
Manufacturer	Happy Co.	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	4.0' wide by 18' long.		

8.2 High Pressure Separator

Device ID #	**100879**	*Device Name*	**High Pressure Separator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	V-100, welded construction, vertical, 3' dia. by 14.3' tall; connected to gas collection system.		

8.3 Sand Trap

Device ID #	**100880**	*Device Name*	**Sand Trap**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	V-200, welded construction, horizontal, 3' dia. by 19.8' long; connected to gas collection system.		

8.4 Low Pressure Separator

Device ID #	**100881**	*Device Name*	**Low Pressure Separator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	V-101, welded construction, vertical, 3' dia. by 14.3' tall; connected to gas collection system.		

8.5 Horizontal Separator

Device ID #	**100888**	*Device Name*	**Horizontal Separator**
Rated Heat Input		*Physical Size*	900.00 Gallons
Manufacturer	King	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	With a separate bottom barrel.		

8.6 Vapor Condensing Coils

Device ID #	**100894**	*Device Name*	**Vapor Condensing Coils**
Rated Heat Input		*Physical Size*	
Manufacturer	Air-X-Changer	*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	0.67' wide by 7.3' long.		

8.7 High Pressure Separator

Device ID #	**100895**	*Device Name*	**High Pressure Separator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	V-100A, welded construction, vertical, 3' dia. by 14.3' tall; connected to gas collection system.		

8.8 Low Pressure Separator

Device ID #	**100896**	*Device Name*	**Low Pressure Separator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	V-101A, welded construction, vertical, 3' dia. by 14.3' tall; connected to gas collection system.		

9 Other Equipment Units (New) at Compressor Plant

9.1 Cooling Motor Fan in Heat Exchanger

Device ID #	**100866**	*Device Name*	**Cooling Motor Fan in Heat Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-2
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 40 hp electric motor.		

9.2 Cooling Motor Fan in Heat Exchanger

Device ID #	**100867**	*Device Name*	**Cooling Motor Fan in Heat Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-3
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 40 hp electric motor.		

9.3 Cooling Motor Fan in Heat Exchanger

Device ID #	**100865**	*Device Name*	**Cooling Motor Fan in Heat Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-1
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 40 hp electric motor.		

9.4 Oil Heater Circulation Pump Motors

Device ID #	**100868**	*Device Name*	**Oil Heater Circulation Pump Motors**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMP-5 A/B
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 40 hp electric motor.		

9.5 Glycol Unit Condenser Fan Motor

Device ID #	**100869**	*Device Name*	**Glycol Unit Condenser Fan Motor**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-4 A/B
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 6 hp electric motor.		

9.6 Glycol Unit Condenser Fan Motor

Device ID #	**100870**	*Device Name*	**Glycol Unit Condenser Fan Motor**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-5
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 5 hp electric motor.		

9.7 Oil Heater Blower Fan

Device ID #	**100872**	*Device Name*	**Oil Heater Blower Fan**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMF-6
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 7.5 hp electric motor.		

9.8 Oil Heater Blower Fan, New

Device ID #	**107541**	*Device Name*	**Oil Heater Blower Fan, New**
Rated Heat Input		*Physical Size*	1.00 Horsepower (Electric Motor)
Manufacturer		*Operator ID*	None
Model		*Serial Number*	
Location Note			
Device Description	Additional blower fan at compressor plant for the oil heater		

10 Equipment Units at 'Dehydration' Plant

10.1 Underground Gas Storage Wells

Device ID #	**008670**	*Device Name*	**Underground Gas Storage Wells**
Rated Heat Input		*Physical Size*	21.00 Total Wells
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

10.2 Accumulator Stack

Device ID #	**100876**	*Device Name*	**Accumulator Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Closed. 2 stacks.		

10.3 Blower

Device ID #	**100897**	*Device Name*	**Blower**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	For VRU at Tank Farm: electric motor, 1.75 hp.		

10.4 Grade Level Loading Station

Device ID #	**008669**	*Device Name*	**Grade Level Loading Station**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Grade level loading station to load HC condensate to tanker trucks by motor driven pump; not equipped with VRU.		

10.5 Gas Stacks/Vents

Device ID #	**100903**	*Device Name*	**Gas Stacks/Vents**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	For pipeline depressurizing operations.		

11 Pumps

11.1 Condensate Pump

Device ID #	**100898**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Serving the storage tanks; 5 hp electric motor drive.		

11.2 Pneumatic Pumps

Device ID #	**100900**	*Device Name*	**Pneumatic Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Serving the methanol tank.		

11.3 Vent Stack Sump Pump

Device ID #	**100904**	*Device Name*	**Vent Stack Sump Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description	Pneumatic.		

11.4 Odorant Metering Pumps

Device ID #	**113419**	*Device Name*	**Odorant Metering Pumps**
Rated Heat Input		*Physical Size*	19.50 MMcf/hr
Manufacturer	YZ Systems	*Operator ID*	
Model	NJEX 8000	*Serial Number*	
Location Note			
Device Description	Air actuated, w/positive displacement and reciprocating plunger. Replaces Device ID 100902		

11.5 Condensate Pumps

Device ID #	**100871**	*Device Name*	**Condensate Pumps**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	EMP-6 A/B
Model		*Serial Number*	
Location Note			
Device Description	Powered by a 1.5 hp electric motor.		

B EXEMPT EQUIPMENT

1 IC Engine: Air Compressor # 4A

Device ID #	**001221**	*Device Name*	**IC Engine: Air Compressor # 4A**
Rated Heat Input		*Physical Size*	48.00 Horsepower
Manufacturer	Waukesha	*Operator ID*	Air Compressor # 4A
Model	VRG220U	*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.F.1.f. Spark ignition piston-type ICEs < =50 bhp /Gas Turbines < = 3 MMBtu/hr	
Location Note			
Device Description	48 hp air compressor engine.		

2 IC Engine: Air Compressor # 5A

Device ID #	**001222**	*Device Name*	**IC Engine: Air Compressor # 5A**
Rated Heat Input		*Physical Size*	48.00 Horsepower
Manufacturer	Waukesha	*Operator ID*	Air Compressor # 5A
Model	VRG220U	*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.F.1.f. Spark ignition piston-type ICEs < =50 bhp /Gas Turbines < = 3 MMBtu/hr	
Location Note			
Device Description	48 hp air compressor engine.		

3 IC Engine: Emergency Electrical Generator

Device ID #	**008665**	*Device Name*	**IC Engine: Emergency Electrical Generator**
Rated Heat Input		*Physical Size*	160.00 Horsepower
Manufacturer	Waukesha	*Operator ID*	
Model	F817GU	*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.F.1.d. Spark ignition piston-type ICEs for emergency electrical power generation	
Location Note			
Device Description	Operated < 200 hours/year. Also included in Part 70 Insignificant Activities.		

4 Air Conditioning System

Device ID #	**100916**	*Device Name*	**Air Conditioning System**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.2 Air Cond/Vent Systm W/No Air Contaminant Removal	
Location Note			
Device Description	Also included in Part 70 Insignificant Activities.		

5 Hot Water Heaters

Device ID #	**100915**	*Device Name*	**Hot Water Heaters**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.G.1 Combustion Equipment < = 2 MMBtu/hr	
Location Note			
Device Description	Also included in Part 70 Insignificant Activities.		

6 Glycol/Glycol Heat Exchanger

Device ID #	**100890**	*Device Name*	**Glycol/Glycol Heat Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Brown Fin Tube	*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description	Parts # E-301, E-302 & E-303, piped in series, 6.5' tall by 24' long.		

7 Glycol/Oil Heat Exchanger

Device ID #	**100891**	*Device Name*	**Glycol/Oil Heat Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Brown Fin Tube	*Operator ID*	E-304
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.L.1 Heat Exchangers	
Location Note			
Device Description	2.5' tall by 20' long, single pass, one component unit.		

8 Glycol Storage Tanks

Device ID #	**100910**	*Device Name*	**Glycol Storage Tanks**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.1 Unheat Storage Of Lqd Org Mtls W/Bp > =300 @ 1 Atm	
Location Note			
Device Description	Two (2) glycol storage tanks and one glycol run tank. Also included in Part 70 Insignificant Activities.		

9 Diesel Tanks

Device ID #	**100911**	*Device Name*	**Diesel Tanks**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.2 Storage Of Refined Fuel Oil W/Grav < =40 Api	
Location Note			
Device Description	Two 110 gallons and one 600 gallons capacity. Also included in Part 70 Insignificant Activities.		

10 Lube Oil Tanks

Device ID #	**100912**	*Device Name*	**Lube Oil Tanks**
Rated Heat Input		*Physical Size*	5000.00 Gallons
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.V.3 Storage Of Lubricating Oils	
Location Note			
Device Description	5000 gallons capacity each. Also included in Part 70 Insignificant Activities.		

11 Degreaser Unit

Device ID #	**100913**	*Device Name*	**Degreaser Unit**
Rated Heat Input		*Physical Size*	
Manufacturer	JRI	*Operator ID*	
Model	TL 21	*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.U.2.c. Use Materials W/Volatile Org Cmpnd <= 2% By Wt	
Location Note			
Device Description	Using non-ROC solvent. Also included in Part 70 Insignificant Activities.		

12 Wipe Cleaning Solvent Usage

Device ID #	**100914**	*Device Name*	**Wipe Cleaning Solvent Usage**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	Yes	*District Rule Exemption:* 202.U.3 Equipment Used In Wipe Cleaning Operations (<55 Gal/Yr At T He Source)	
Location Note			
Device Description	Also included in Part 70 Insignificant Activities.		

10.6 Permittee Comments on the Draft Permit and the District Responses

SoCalGas Comments on Draft Part 70/District PTO NO. 9584-R4 (LaGoleta Plant)

No.	Page/ Section	SoCalGas Citation and Issue	SoCalGas Proposed Resolution	District Response
1	1.2.2	The SulfaTreat vessel only operates in series with one of 2 KMN vessels.	Revise description.	The process description was revised to clarify that there are two parallel systems, each consisting of one SulfaTreat vessel and one KMN vessel in series.
2	3.2.5	Subpart ZZZZ discussion. The EPA is still resolving comments on the rule and another revision is likely.	Remove the details of the rule compliance discussion.	The discussion of the current rule requirements will remain. Language was added stating that the District will enforce the revised version of the rule, if the revisions are finalized. Additional language was added clarifying that SoCalGas has the option of conducting oil analyses in lieu of oil changes.
3	3.2.6	The paragraph referred to an old version of the CAM plan.	Update the reference.	The reference to a specific version of the CAM plan was removed. Condition C.16 specifies the current version at the date of permit issuance.
4	3.5.1	NOV 9434 was rescinded.	Remove the discussion of the NOV.	The discussion will remain in the permit for completeness. The discussion notes that the NOV was rescinded.
5	4.4.1	The component count does not match the current count.	Update the count.	The component count was removed from this section and a reference was inserted to the count specified in Table 5.1-1.
6	4.7.4	Sulfur removal unit discussion.	Update the discussion to match the current configuration.	Done.
7	5.7	PTO 13479 is not included in the list of permits.	Add PTO 13479 to the list.	Done.
8	Table 5.2	Clarify whether GHG totals are emission limits.	Add language to the permit.	Section 5.4 was revised to clarify that the emission totals are included in the table to document the potential to emit of the facility. Because the PTE is below 100,000 tpy CO_{2e} GHG emissions from the facility are not subject to regulation under Part 70.

No.	Page/ Section	SoCalGas Citation and Issue	SoCalGas Proposed Resolution	District Response
9	Table 5.3	Pipeline/well venting emissions have been exempt from federal permitting since the original permit was issued.	Remove them from Table 5.3 (Federal PTE)	Table 5.3 documents the PTE of the facility for the purpose of determining whether the facility is a major source subject to Part 70 permitting requirements. Gas that is vented through a stack during pipeline and well depressurization does not meet the definition of "fugitive emissions" in Part 70, therefore it is included in the PTE for the purpose of determining whether the facility is a major source for Part 70 purposes.
10	Condition 9.A.5	Indemnity and Separation Clause	Request the new language be removed and the severability clause language remain.	The requested change was made. The severability clause from PT-70/PTO 9584-R3 was re-inserted.
11	C.1.(b)(vi)E	Replacement Reporting	Revise language for consistency with District guidance. If a catalyst is replaced, testing will be conducted in accordance with the approved I&M plan.	Done.
12	C.16	Documents incorporated by reference	Update references to list the most current plans.	Done.
13	10.1	HAP sampling	This sampling is completed; remove the reference to further sampling.	Done.
14	10.5	Exempt Equipment List	Device ID 107731 does not exist, Device ID 008665 does exist.	These two entries are both for Waukesha F817GU 160 bhp emergency standby IC engines. It appears device ID 107731 is a duplicate entry to Device ID 008665. Device ID 107731 has been deleted.