DRAFT

PERMIT to OPERATE No. 5704

and

PART 70 OPERATING PERMIT No. 5704

GAVIOTA OIL HEATING FACILITY

POINT ARGUELLO PROJECT STATIONARY SOURCE

GAVIOTA OIL HEATING FACILITY
17100 CALLE MARIPOSA REINA, GAVIOTA, CA

EQUIPMENT OPERATOR

Plains Exploration and Production Co. (PXP)

OWNERSHIP

Plains Exploration and Production Co.(PXP); Texaco Harvest Pipeline Co.; Texaco Harvest Gas Pipeline Co.; Sisquoc Gas Oil Pipeline Co.; Sun Offshore Gathering Co.; Whiting Programs Inc.; Koch Exploration Co.; Harvest Energy, Inc.; Capitan Oil Pipeline Co; Cachuma Gas Processing Co.

Santa Barbara County
Air Pollution Control District

July 2008

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
APCD	Santa Barbara County Air Pollution Control District
API	American Petroleum Institute
AQMM R&O	Air Quality and Meteorological Monitoring Protocol
ASTM	American Society for Testing Materials
ATC	Authority to Construct
BACT	Best Available Control Technology
bpd	barrels per day (1 barrel = 42 gallons)
Btu	British thermal unit
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
CPP	cogeneration power plant
dscf	dry standard cubic foot
E100	emitters less than 100 ppmv
E500	emitters less than 500 ppmv
EQ	equipment
ESE	entire source emissions
EU	emission unit
°F	degree Fahrenheit
FID	facility identification
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	Inspection & Maintenance
ISO	International Standards Organization
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
GOHF	Gaviota Oil Heating Facility
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NAR	Nonattainment Review
NEI	net emissions increase
NGL	natural gas liquids
NG	natural gas
NH_3	ammonia
NSPS	New Source Performance Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
O_2	oxygen

OCS	outer continental shelf
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
ppm(vd or w)	parts per million (volume dry or weight)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PRD/PSV	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
SSID	stationary source identification
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
THC, TOC	total hydrocarbons, total organic compounds
tpq, TPQ	tons per quarter
tpy, TPY	tons per year
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system
w.c.	water column

1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District ("APCD) is responsible for implementing all applicable federal, state and local air pollution requirements which 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, 55, 60, 61, 63, 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 APCD's Rules and Regulations. The County is currently designated as a non-attainment area for the state ozone and PM_{10} ambient air quality standards.

Part 70 Permitting. This is a combined permitting action that covers both the Federal Part 70 permit (*Part 70 Operating Permit No. 5704*) as well as the State Operating Permit (*Permit to Operate No. 5704*). The first permit renewal occurred in April 2001 and the second renewal in July 2005. This is the third renewal of the Part 70 permit, as well as, the APCD reevaluation, and may include additional applicable requirements. . Several Part 70 minor modifications since initial Part 70 permit issuance have been incorporated into this permit.

GOHF is a part of the *Point Arguello Project* stationary source (SSID = 1325), which is a major source for VOC[1], NO_x, SOx 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 APCD, 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.

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. Second, 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.

[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.

1.2 *Facility/Project/Stationary Source Overview*

1.2.1 Facility: GOHF was originally designed and operated as an oil and gas processing facility for crude and natural gas produced from OCS platforms Hermosa, Hidalgo and Harvest. Due to contractual requirements to reduce emissions and declining field production, several significant modifications have been made to GOHF to extend the economic life of the project. These modifications (April 2000) consisted of the de-permitting of all gas processing equipment and the 'removal from service[2]' of much of the oil processing equipment. With the exception of a small volume of natural gas delivered to the GOHF through existing pipelines for use as fuel gas, platform natural gas production that was formerly processed at GOHF is currently reinjected at the platforms or utilized as platform fuel. The crude is processed on the platforms prior to shipment to the GOHF. The only treatment occurring at GOHF is the heating of the crude to pipeline quality specifications prior to delivery to the All American Pipeline Pump Station (AAPL) located adjacent to the GOHF. The Gaviota Pipeline Terminal (GPT), located directly across Highway 101, stores the crude as necessary and delivers it to the AAPL pipeline for transport to refineries.

Project: The GOHF is part of the Point Arguello Project which produces oil and gas from the Point Arguello Field located in the Santa Maria Offshore Basin. The project was originally issued ATC 5704 on February 6, 1986 with oil and gas production commencing in 1989 from offshore platforms Hermosa, Hidalgo and Harvest. Each of these platforms currently produces crude oil which is shipped by pipeline to the GOHF through a 24-inch crude oil transmission line.

Stationary Source: GOHF is part of the *Point Arguello Project* stationary source (SSID = 1325). The *Point Arguello Project* stationary source consists of the following 4 facilities:

- GOHF (FID= 1325)
- Platform Harvest (FID= 8013)
- Platform Hermosa (FID= 8014)
- Platform Hidalgo (FID= 8015)

The GOHF is the primary facility addressed in this permit. Each platform is subject to individual permits pursuant to OCS regulation 40 CFR Part 55. The platforms are addressed in this permit only with respect to lead agency (Santa Barbara County Planning and Development) requirements as outlined in the various agreements and contract entered into between PXP, the county and the APCD. Individual Part 70 permits have been issued for each platform.

[2] Equipment 'removed from service' is equipment that has been taken out of service but not de-permitted. Permit condition 9.C.31 provides details regarding the restrictions involved in operating this equipment.

1.2.2 Facility New Source Review Overview: Since the issuance of the initial Pt-70 operating permit on April 19, 2001, the following permit actions have been issued:

ATC/PTO 10332	08/23/01	Installation of H_2S Sensors at the GOHF
ATC/PTO 10332-01	12/12/01	Modification to ATC/PTO 10332 (revision to monitoring requirements).
ATC/PTO 10332-02	06/27/02	Modification to ATC/PTO 10332-01 (Changes to the number and manufacturer of the H_2S sensors).
ATC 10394	03/23/01	Installation of fuel gas H_2S scavenging equipment.
ATC 10439	05/25/01	Reallocation of ERCs.
ATC 11034	09/15/03	Installation of Temporary Flare.
ATC/PTO 11203	05/20/04	Modification to the Turbine starter engines allowable run time.
ATC/PTO 11816	10/31/05	Increase H_2S concentration of GOHF fuel gas.
ATC 11211-01	01/27/06	Modification to ATC 11211 to increase the number of fugitive components.

Additionally, the following PTOs / PTO modifications have been issued:

PTO 5704-06	12/04/01	Modification to VEE Condition 9.B.2.
PTO 5704-07	07/10/03	Revision to MERC ERCs.
PTO 5704-08	10/16/03	Modification to Turbine Starter Engine Use.
PTO 5704-09	02/23/04	Removal of permit condition restricting use of Tank T-1 to emergency use only.
PTO 5704-10	02/03/05	Remove Sigma VWS from Carp. Ambient Monitoring Station.
Trn O/O 5704-05	10/06/05	Change of Ownership

PTO 11513	12/19/05	Installation of one emergency firewater pump due to the loss of the Rule 202.F.1.d exemption.
PTO 5704-12	06/28/07	Replacement of MERC emission reduction credits with credits generated by the installation of emission controls on gas operated turbines on Platform Harvest.
PTO 5704-13	03/13/07	Remove 100-day use restriction from tank T-2.
Trn O/O 5704-06	06/27/07	Change of Operator

1.3 Emission Sources

Plant primary source of emissions result from operation of the following equipment:

Cogeneration Plant. This plant includes five 3.5 MW gas turbine driven electric power generators, five waste heat recovery steam generators (HRSG), a selective Catalytic Reduction unit (SCR) duct burner and five diesel operated turbine starter engines. PXP has de-rated GOHF such that operations are limited to the simultaneous operation of three turbines, two HRSGs and one SCR burner.

Fugitive Hydrocarbon Emissions. Hydrocarbon emissions occur from piping component leaks such as valves, flanges and other fittings as well as compressor and pump seals.

Miscellaneous. Flare, various crude and waste water tanks and solvent use.

Section 4 of this permit provides the APCD's engineering analysis of these emission sources. Section 5 of this permit describes the allowable emissions from each permitted emissions unit and also lists the potential emissions from non-permitted emission units.

1.4 Emission Control Overview

Air pollution emission controls are utilized at the plant. The emission controls employed at the facility include:

- The Cogeneration plant utilizes turbine water injection and selective catalytic reduction with ammonia injection to control NO_x emissions.

- A Fugitive Inspection & Maintenance program for detecting and repairing leaks of hydrocarbons from piping components to reduce ROC emissions by approximately 80 percent, consistent with the BACT requirements of ATC 5704 and modifications thereof and Rule 331.

- Use of a vapor recovery system to collect hydrocarbon vapors from various tanks, sumps and drains.

- Chemical injection to reduce H_2S in the fuel gas and gas routed to flare.

- Use of pipeline quality natural gas as fuel gas for all gas combustion units.

1.5 Offsets/Emission Reduction Credit Overview

Emissions from the Point Arguello Project must be offset pursuant to the APCD's New Source Review regulation. Specifically, during the original permitting of this project, offsets were required for ROC and NO_x for the GOHF emissions as well as the platform emissions. The agreement entitled "*Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Project Preliminary Development Plan No. 83-DP-32-CZ*", (signed August 19, 1985, and amended on September 8, 1992), hereinafter referred to as the "Arguello /APCD Contract" details the emission offsets required for the project. A copy of this contract is located in the project file. Section 7 details the offset requirements for the project.

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 APCD Rules, all conditions in the APCD-issued Authority to Construct permits and all conditions applicable to major sources under federally promulgated rules and regulations. All permits (and conditions therein) issued pursuant to the OCS Air Regulation are federally enforceable. All these requirements are enforceable by the public under CAAA. (*see Section 3 for a list of the federally enforceable requirements).*

1.6.2 Insignificant Emissions Units: The criteria for treating a unit as insignificant are that regulated air pollutants emitted from the unit, excluding HAPs, are less than 2 tons per year potential to emit and that any HAP regulated under section 112(g) of the Clean Air Act does not exceed 0.5 ton per year 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, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.0 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 APCD. Permit shields cannot be indiscriminately granted with respect to all federal requirements. PXP has not made any requests for permit shields.

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. PXP has not made any requests for 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 or on a more frequent schedule specified in the permit. Each certification is signed by the "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit. *(see Section 1.6.9 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. This permit may be re-opened in the future to address new monitoring rules, if the permit is revised significantly prior to its first expiration date.

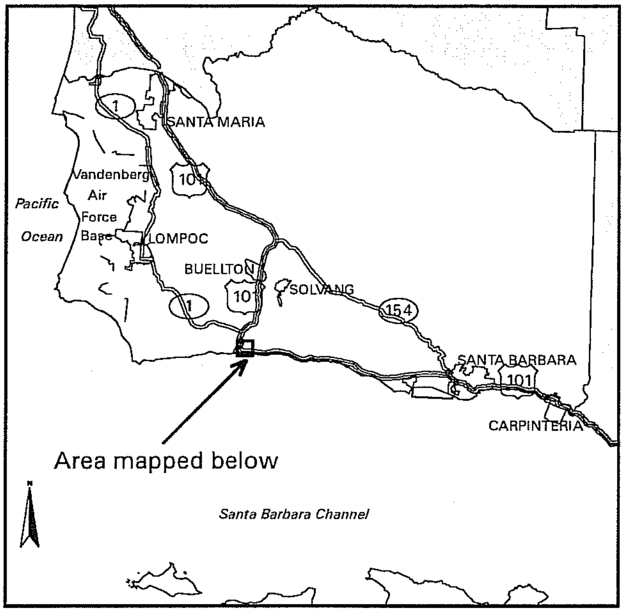
1.6.8 Hazardous Air Pollutants ("HAPs"): The requirements of Part 70 permits also regulate HAPs emissions from major sources through the imposition of maximum achievable control technology ("MACT"), where applicable. The federal PTE for HAP emissions from a source is computed to determine MACT or any other rule applicability.

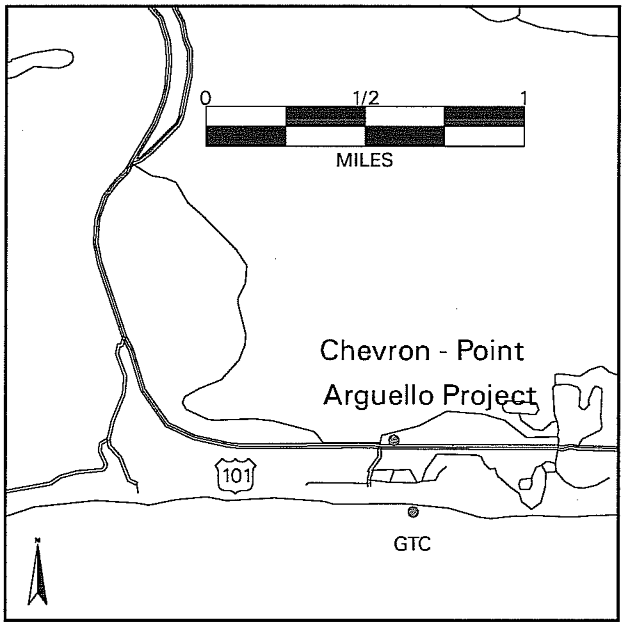
1.6.9 Responsible Official: The designated responsible official and his mailing address is:

Thomas Goeres, Operations Manager
Plains Exploration and Production Company (PXP)
201 So. Broadway
Orcutt, CA 93455

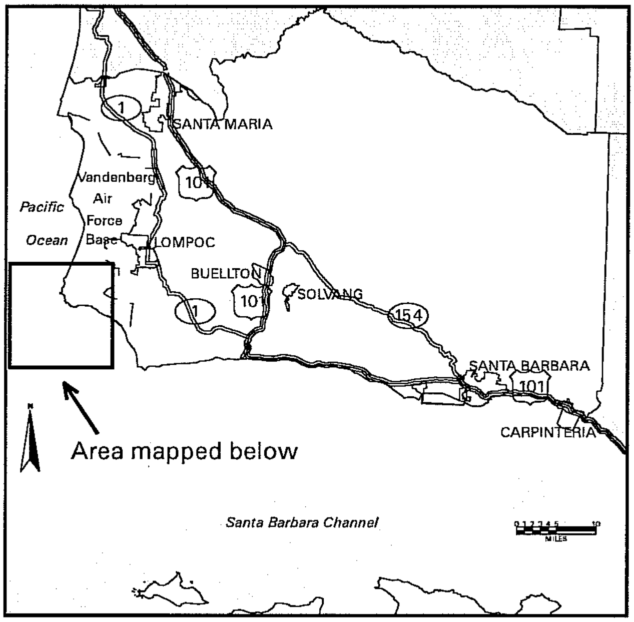
Figure 1.1 - Location Map

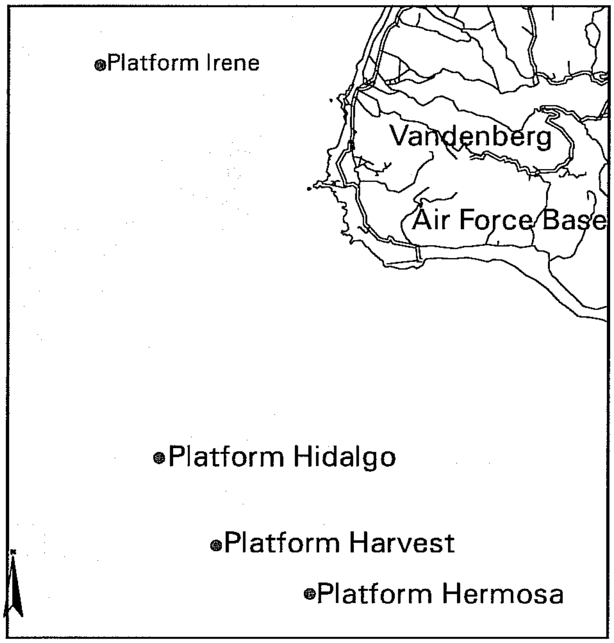
Point Arguello Project (onshore)





Point Arguello Project (offshore)





2.0 Description of Proposed Project and Process Description

2.1 Project and Process Description

2.1.1 Project Ownership

The Point Arguello Companies Partnership is the owner and Plains Exploration and Production Company the operator of the GOHF. PXP is a member of the Point Arguello Companies Partnership.

2.1.2 Geographic Location

The GOHF is located approximately 28 miles west of the City of Santa Barbara at 17100 Calle Mariposa Reina. The facility sits on a 56.9 acre parcel of land on the north side of U.S. highway 101. See Figure 1.1 (Location Map) for additional detail.

2.1.3 Operations History

Permit to Operate 5704 was issued for GOHF on March 26, 1996. That permit authorized the processing of up to 125,000 barrels per day of wet oil; 60 million standard cubic feet per day (MMSCFD) of gas; 531,286 SCFD (based on 20 long tons) of H_2S in the amine units; and, sour gas containing up to 20,000 ppmv H_2S. The onsite cogeneration plant was permitted to generate 14.0 megawatts of electricity. As discussed below, significant reductions in these permitted throughput capacities commenced in 1998.

The first significant modification was authorized under ATC/PTO 9933 (July 14, 1998) to satisfy the requirements of the Third Amendment to the Ozone Mitigation Agreement ("OMA") dated May 20, 1997. The OMA required the reduction in NO_x potential to emit ("PTE") and associated ROC emissions from fuel burning equipment by 30 tons per year ("tpy") at the GOHF. The OMA also required a reduction of in-service fugitive emission components at GOHF to achieve an actual emission reduction of 20 tpy of non-ethane ROC emissions.

To achieve the required NO_x PTE and ROC fugitive emission reductions, specific equipment items were removed from service. Two oil trains, one amine plant, one V-1001 and one F-1000 unit were removed from service but remained on permit and were allowed to be returned to service provided similar equipment is simultaneously shutdown or the permit is modified to increase emission limits. One cogeneration plant turbine and two fuel gas systems were also removed from service.

Additional equipment removed from service under ATC/PTO 9933 was V-1B, 5 V-21s, P-36, the butane line, butane loading rack, PCV-T30, Plant 17, 3 FE-V2-5s, T-5B, V-1500, P-1500A&B, and two V-20s). A permit application is required to return any of this equipment to service.

Removal from service of the above mentioned equipment effectively de-rated the facility so that operations were limited to one oil train, one amine plant, one V-1001 unit and one F-1000 unit. The facility throughput limit was reduced to 62,500 barrels per day of wet oil; 30 million standard cubic feet per day (MMSCFD) of gas; and, 265,643 SCFD (based on 10 long tons) of H_2S in one amine unit. The cogeneration plant electrical power generation was reduced to 10.5 megawatts.

On October 7, 1998 Authority to Construct/Permit to Operate 9940 was issued and authorized the GOHF modifications referred to as "Reconfiguration I". The GOHF was reconfigured to the extent that, with the exception of a small volume of natural gas delivered to the GOHF for plant fuel use, gas is no longer shipped to the GOHF for processing and is reinjected at the platform or used as fuel. Primary processing of the crude oil is performed on Platforms Harvest and Hermosa. The only processing operations currently occurring at the GOHF is the heating of the crude to pipeline specifications and chemical treatment of vapors to reduce sulfur emissions.

ATC/PTO 9940 also included the routing of the vapor recovery unit emissions to the flare since the gas processing facilities could no longer accept this gas. The H_2S content of these vapors required the injection of H_2S reducing chemical to meet APCD rule and SO_x emission limits.

The gas processing facilities were formally de-permitted, thereby prohibiting the processing of natural gas at the plant, under Authority to Construct/Permit to Operate 10199 (April 12, 2000).

2.1.4 Current Operations/Processing Facilities

Crude Oil Heating: Crude oil from the offshore platforms transported via the DOT regulated PAPCO pipeline enters the GOHF at about 59-70°F and 70 psig. The oil is metered at one of the three oil LACT units for pipeline leak detection purposes. Oil leaving the oil LACT unit enters the free water knockout, V-1A, which provides back pressure control and surge capacity. The free water knockout operates at about 100 psig and relieves to the flare at 160 psig. The pressure in V-1A is maintained by fuel gas makeup. The level in the vessel is automatically controlled to minimize the need for fuel gas makeup and to prevent unnecessary flare emissions. Typical operations bypass V-1A completely..

Oil leaving V-1A and the vessel bypass is heated in oil heat exchanger, E-3B; from about 59 to 70°F up to approximately 90°F. Steam generated at the onsite cogeneration plant provides the heating medium at E-3B. Hot crude oil leaving E-3B is sent directly to the shipping tank T-1. Oil may also be diverted to the 40,000-barrel capacity reject oil tank, T-2, through a bypass line downstream of E-3B. Oil is then moved from tank T-1 using pumps 601-A/B/C/D through heat exchanger E-3C and then routed at the pipeline specified temperature of 120-130°F to the All American Pipeline. The oil goes through one of two oil LACT units for metering.

Tank T-2 normally serves as a reject oil tank. The level in tank T-2 is normally kept at a minimum. The tank has a minimum 4 foot depth of water at all times. The tank primarily receives the following streams: full flow relief-valves upstream of the wet LACT are set at 250 psig to protect equipment from overpressure when there is a sudden valve closure or blockage downstream. The full flow relief valves allow oil from the pipeline to divert to tank T-2. The following may also be diverted to tank T-2: water accumulated at the bottom of V-1A; heated oil diverted manually downstream of E-3B; oil skimmed from tank T-25; and dry oil not meeting pipeline specification at the dry oil LACT unit and fluids from V-50 (oil plant flare header knockouts) using P-25 A and B and pigging fluids.

From tank T-2, recycle oil pumps P-5A and P-5B are used to rerun skimmed or reject oil to the inlet of V-1A. Water may also be pumped to upstream of V-1A and blended with the inlet oil to the extent the oil meets pipeline specifications.

Tank T-25 is a 1,300-barrel capacity tank that collects primarily skimmed oil and process drainage. In the tank, water is separated from oil for disposal while oil is returned to the process. Main feed streams to T-25 are the oily water sewer system, oil skimmed from run-off impoundment pond, oil skimmed from water tanks, impound water that does not meet discharge specifications, and boiler blowdown when the raw water treating unit is not in service. Tank T-25 is skimmed regularly. Skimmed oil is pumped to T-2 using pumps P-50A/B and then to the inlet of V-1A for reprocessing. Water in T-25 is also pumped by P-50A/B to tank T-8 for further removal of oil. It is then pumped through polishing filters and is pumped by pump P-61 into an injection well for disposal.

The T-4 wastewater tank is currently out of service but remains on permit.

Crude Tank Blanketing and Vapor Recovery: Sweet natural gas is supplied to GOHF primarily from Platform Hermosa through the PANGL pipeline. Gas from the pipeline enters the plant through vessel V-1000 to drop out any residual moisture that accumulates in the pipeline. Gas is also supplied on a backup basis by the Southern California Gas Company pipeline. This natural gas is used as fuel for the cogeneration plant and a blanket gas for the plant tank battery.

The VRU collects vapors from the oil and wastewater tanks T-1, T-2, T-8 and T-25. VRU compressors, K-3 and K-3A, and fuel gas makeup maintain the VRU header pressure at about 1.2-inches water column. Tank vapors are routed through knockout vessel V-51, compressed by the VRU compressors and then discharged into the fuel gas recovery vessels V-1001A and B.

Fuel Gas Recovery System: Vessels V-1001A and B are used to store vapors recovered by the VRU system. V-1001A is the primary storage vessel with operating pressure of 60 psig. Gases in this vessel are routed to the suction of compressors K-1230A and B. the compressors raise this gas stream to 275 psig which is then blended into the fuel gas stream for the cogeneration plant. The secondary vessel, V-1001B, can also be connected to the PANGL pipeline and used up to an operating pressure of 275 psig when gas pigging operations are occurring. Gases from V-1001B are also routed to the suction side of K-1230A and B.

Flare Relief System: The flare system collects and combusts vapors from oil and produced water tanks T-1, T-2, T-8 and T-25 that are served by the VRU system that are not reused for fuel gas, vapors released by pressure safety valves tied into the flare system, and vapors routed to the flare header from plant equipment degassing and inerting activities.

The flare is steam assisted and is equipped with an igniter system and pilot flame, which is always lit. The steam cools the flare tip and induces oxygen within the combustion zone to ensure complete combustion to reduce the formation of smoke and the release of volatile organic compounds. Purge gas (fuel gas or nitrogen) provides a continuous gas flow through the flare stack to prevent ambient air ingress into the flare system. Vapors routed to the flare go through knockout vessels, V-7120 A&B, and as needed, are treated with H_2S scavenging chemicals to reduce the sulfur content in the flared gas.

The base of the flare is equipped with two water seals to provide two levels of back-pressure. In this configuration, the water in at least one of the seals must be removed for a flaring event to occur. The water seal located on the 6-inch diameter bypass line provides 21 inches of water column back-pressure. The second water seal is located on the 42-inch diameter main flare line in the flare base and provides 30 inches of water column back-pressure.

The volume of gas flared is metered. The gas composition is measured by a gas chromatograph. The H_2S content is also measured by an H_2S analyzer, gas chromatograph or by color indicating tubes, as appropriate.

Cogeneration Plant: Cogeneration Plant, comprised of five 3.5 MW gas turbine driven generators manufactured by Allison (Model number 501-KB), provides electrical power and steam to meet facility needs. The turbine exhaust gas is routed through its respective heat recovery steam generator (HRSG) to recover heat and generate steam for the plant. The HRSGs are also equipped with gas burners to provide supplemental steam capacity for the plant. Exhaust gases from each HRSG are routed to a common duct, which is also equipped with an in-line duct burner and a non-fired waste heat recovery boiler.

Each turbine is equipped with water injection to reduce NO_x emissions in the combustion chamber. Flue gas from the turbines and the HRSG is combined and routed through a selective catalytic reduction (SCR) unit. Ammonia (NH_3) is injected to convert nitrogen oxides to nitrogen, thus reducing stack emissions. The catalyst is maintained at the optimum operating temperatures by heat from the turbines or the SCR burner. Currently, any three turbines, any two HRSGs and the SCR burner are permitted to operate simultaneously.

The fuel gas requirements for the GOHF are met by the shipment of natural gas from platform Hermosa and the injection of vapor recovery vapors into the fuel gas system. The fuel can be treated with H_2S scavenging chemical to ensure that it meets the BACT total sulfur content limit of 4 ppmv (as H_2S).

GOHF power output exceeds the facility electrical power needs. Surplus power is sold to a utility company and steam produced by the plant's HRSG is used to heat oil at E-3B.

Desalination Plant. Fresh water for GOHF is produced by seawater desalination. Seawater is pumped to the plant, filtered and processed through two of three reverse osmosis trains. About 200 gallons per minute of freshwater is produced. This water is chlorinated for use as drinking water or softened for use as steam generator feed water. Part of the water is further purified to produce process water. The remaining portion is deionized and used for injection into the gas turbines for NO_x emission control.

3.0 Regulatory Review

3.1 Rule Exemptions

⇒ APCD Rule 202 (*Exemptions to Rule 201*): PXPhas requested a number of permit exemptions under this rule. An exemption from permit, however, does not grant relief from any applicable prohibitory rule unless specifically exempted by that prohibitory rule. The following exemptions are approved by the APCD:

- Section D.6 for fugitive emission *de minimis* increases.
- Section D.8 for routine repair or maintenance activities that meet the specified criteria in this provision.
- Section D.14 for application of architectural coatings in the repair and maintenance of a stationary source.
- Section 202.U.2 for solvent application equipment and operations if the degreasing equipment contains unheated solvent and has a liquid surface area of less than 1 square foot and that the cumulative surface area of all the degreasers is less than 10 square feet.
- Section 202.U.3 for wipe cleaning using solvents as long as the solvents meet other applicable requirements and the use does not exceed 55 gallons per year.

⇒ APCD Rule 331 (*Fugitive Emissions Inspection and Maintenance*): The following components are exempt from certain/all provisions of the rule:

- Components buried below ground (exempt from all requirements)
- One half inch and smaller stainless steel tube fittings that have been determined to be leak free by the Control Officer (exempt from all requirements)
- Components totally contained or enclosed such that there are no ROC emissions into the atmosphere are exempt from Sections F.1, F.2, F.3 and F.7.
- Components that are unsafe-to-monitor, as documented and established in a safety manual or policy, and with prior written approval of the Control Officer are exempt from Sections F.1, F.2 and F.7.

⇒ APCD Rule 333 (*Control of Emissions From Reciprocating Internal Combustion Engines*): Section B.1.b exempts engines that are exempt from permit per Rule 202 from all the requirements of this rule. The five turbine starters are not exempt from permit, but due to their restricted annual hours they are exempt from all sections of Rule 333 except section H.

⇒ Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): The turbine starter engines are exempt from section e(2)(D)1 this rule based on section (e)12 which requires that:

(a) the engines are prime engines;
(b)the engines are located more than 500 feet from a school at all times;
(c) each engine operates no more than 20 hours cumulatively per year.

All other sections must be adhered to, as applicable.

3.2 Compliance with Applicable Federal Rules and Regulations

3.2.1 40 CFR Parts 51/52{*New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration)*}: The GOHF was originally permitted in February 6, 1986 under APCD Rule 205.C. That rule was superseded by APCD Regulation VIII (*New Source Review*) in April 1997. Compliance with PTO 5704 requirements and Regulation VIII ensures that this facility will comply with federal NSR requirements.

3.2.2 40 CFR Part 60 {*New Source Performance Standards*}: The following NSPS apply at the GOHF facility:

Subpart A General Provisions.

Subpart GG (Section 60.332) - Standards of Performance for Stationary Gas Turbines: This subpart requires stationary gas turbines rated between 10 and 100 MMBtu/hr to meet a NO_x emission limit calculated per section 60.332 of subpart GG and a fuel sulfur content limit of 0.8 % by weight.

Each turbine at this facility is subject to these standards. Since APCD Rule 311 is more stringent for fuel sulfur content, the GG sulfur content standard has been subsumed into Rule 311.

The applicable NO_x standard was determined to be 190 ppmv at 15% O_2 in accordance with section 60.332(a)(2). "Y" was assumed to be 14.4 to provide the most conservative calculated value. "N" was assumed to be 0.3 % (as a worst case) based on natural gas turbine fuel data.

The maximum NO_x concentration allowed by this permit is 19 ppmvd at 3 percent oxygen. Converting the 19 ppmvd at 3 percent oxygen to concentration at 15 percent oxygen results in an approximate NO_x concentration of 6.3 ppmvd. Water injection, monitoring and reporting requirements, similar to that required by this subpart, are summarized in permit condition 9.C.1. A NO_x continuous emissions monitor is required under this permit for purposes demonstrating compliance with this 19 ppmvd standard. The APCD has determined that PXP has implemented, and is in compliance with, all requirements of this subpart.

Subpart Kb — Standards of Performance for Volatile Organic Liquid Storage Vessels: This section requires controls for tanks storing volatile organic compounds. Controls include the use of a fixed roof tank in combination with a floating roof, an external floating roof, or a vapor recovery system. PXP has implemented the use of a vapor recovery system. This subpart also details testing procedures, and recordkeeping and reporting requirements.

All but two of PXP's oil and oil/water storage tanks are exempt from the requirements of this subpart pursuant to Section I 10b.d, exemption 4, due to the tanks having capacities less than 1,589.874 cubic meters (10,000 bbl). The dry oil tank (T-1) and reject oil tank (T-2) have capacities of 10,000 bbls and 40,000 bbls, respectively and are subject to this subpart. These tanks are equipped with fixed roofs and a vapor recovery system consistent with the requirements, of 60.112b.a.3. The APCD has confirmed that PXP has implemented and is in compliance with all requirements of this subpart.

3.2.3 40 CFR Part 61 {*NESHAP*}: This facility is not currently subject to the provisions of this Subpart.

3.2.4 40 CFR Part 63 {*MACT*}: On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. PXP submitted an *Initial Notification of Applicability* on June 13, 2000 PXP subsequently claimed a black oil exemption per 63.760.e.1. Data was submitted on July 14, 2000 to support this exemption for the facility as currently permitted. The APCD approved the exemption request on October 25, 2000. This exemption requires that records be maintained in accordance with 40 CFR 63.10(b)(3). See permit condition 9.B.13.

3.2.5 40 CFR Part 63; Subpart YYYY {*MACT*}: On March 5, 2004, EPA promulgated Subpart YYYY, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Stationary Combustion Turbines. This subpart applies to anyone who owns or operates a stationary combustion turbine located at a major source of HAP emissions. A major source of HAP emissions is defined as a contiguous site under common control that emits, or has the potential to emit, ten tons per year or more of any single HAP or a combination of HAP exceeding 25 tons per year. The GOHF HAP emission totals are less than each of the above thresholds and therefore, this subpart is not applicable.

3.2.6 40 CFR Part 64 {*Compliance Assurance Monitoring*}:
This rule became effective on April 22, 1998 and applies to emission units that; (1) use a control device to comply with a federally enforceable emission standard, and (2) the pre-control emissions of any one controlled pollutant exceeds 100 tpy. The turbines at this facility meet these criterion however, they are equipped with continuous emission monitors (CEMs) and therefore are exempt from this rule per section 64.2(b)(1)(vi).

3.2.7 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to the GOHF. Table 3.1 lists the federally-enforceable APCD promulgated rules that are "generic" and apply to the facility. Table 3.2 lists the federally-enforceable APCD promulgated rules that are "unit-specific". These tables are based on data available from the APCD's administrative files and from PXP's Part 70 Operating Permit application. Table 3.4 includes the adoption dates of these rules.

In its Part 70 permit renewal application (Form I) PXP certified compliance with all existing APCD rules and permit conditions. This certification is also required of PXP semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that PXP 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.

3.3.2 California Administrative Code Title 17: These sections specify the standards by which abrasive blasting activities are governed throughout the state. All abrasive blasting activities at the GOHF are required to conform to these standards. Compliance is typically assessed through onsite inspections. However, CAC Title 17 does not preempt enforcement of any SIP-approved rule that may be applicable to abrasive blasting activities.

3.3.3 Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): This ATCM applies for all stationary diesel-fueled engines rated above 50 brake horsepower (bhp) at this facility. On March 17, 2005, APCD Rule 202 was revised to remove the compression-ignited engine (e.g. diesel) permit exemption for units rated over 50 bhp to allow the APCD to implement the State's ATCM for Stationary Compression Ignition Engines. The diesel firewater pump and turbine starter engines are subject to the ATCM. Compliance shall be assessed through onsite inspections and reporting Compliance shall be assessed through onsite inspections and reporting.

3.4 Compliance with Applicable Local Rules and Regulations

3.4.1 Applicability Tables: In addition to Tables 3.1 and 3.2, Table 3.3 lists the non-federally enforceable APCD promulgated rules that apply to the plant. Table 3.4 lists the adoption date of all rules applicable to this permit at the date of this permit's issuance.

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 the plant:

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 SBCAPCD rules and regulations. To the best of the APCD's knowledge, PXP is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for 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 flare, the turbines, the heat recovery steam generators and the diesel-fired internal combustion engine driving the firewater pump; regardless of exemption status. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be assured by onsite inspections and proper operation and maintenance of all internal combustion engines.

Rule 303 - Nuisance: This rule prohibits PXP from causing a public nuisance due to the discharge of air contaminants. All nuisance complaints are investigated by the APCD and follow the guidelines outlined in APCD RCD Policy & Procedure I.G.2 (*Compliance Investigations*). This rule is included in the SIP.

Rule 305 - Particulate Matter, Northern Zone: The GOHF is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of the specified concentrations measured in grains per standard cubic feet ("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. Sources subject to this rule include: the flare and all diesel-fired IC engines. Compliance will be assured by requiring all engines and the flare system to be maintained according to manufacturer maintenance schedules.

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 0.1 gr/scf (at 12% CO_2) respectively. Sulfur emissions due to planned flaring events will comply with the SO_2 limit. The diesel powered piston IC engine driving the emergency firewater pump has the potential to exceed the combustion contaminant limit if not properly maintained, however continued compliance will be assured by requiring this engine and the flare system to be maintained according to manufacturers specifications.

Rule 310 - Odorous Organic Compounds: This rule prohibits the discharge of H_2S and organic sulfides that result in a ground level impact beyond the property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. The de-permitting of gas producing equipment, continued implementation of the APCD-approved Odor Monitoring Plan and the injection of H_2S reducing chemical is anticipated to assure compliance with this rule.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted to 0.5 percent (by wt) for liquids fuels and 50 gr/100 scf (calculated as H_2S) {or 239 ppmvd) for gaseous fuels. All piston IC engines are in compliance with the liquid fuel limit as determined by fuel analysis documentation. The gaseous sulfur limit applies to operation of the cogeneration units. The fuel gas system is equipped with an H_2S monitor to ensure compliance with this rule.

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the usage of both photo-chemically and non-photo-chemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used 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. PXP is required to maintain records to ensure compliance with this rule.

Rule 321 - Control of Degreasing Operations: This rule sets equipment and operational standards for degreasers using organic solvents. There are no degreasers using organic solvents at this facility.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photo-chemically reactive solvents for use as thinners or reducers in metal surface coatings. PXP is required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for many types of architectural coatings. The primary coating standard that will apply to the platform is for Industrial Maintenance Coatings which has a limit of 340 gram ROC per liter of coating, as applied. PXP is required to maintain records to verify compliance with this rule.

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

Rule 325 - Crude Oil Production and Separation: This rule, adopted January 25, 1994, applies to equipment used in the production, gathering, storage, processing and separation of crude oil and gas prior to custody transfer. The primary requirements of this rule are contained in Sections D and E. Section D requires the use of vapor recovery systems on all tanks and vessels, including waste water tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. This rule also requires that all produced gas be controlled at all times, either by directing produced gases to a gas system for handling gas for fuel sale or underground storage, a flare or a device with a minimum ROC destruction efficiency of 90%.

All production vessels and tanks are connected to the VRS and all relief valves are connected to the flare relief system. PXP has installed vapor recovery on all equipment subject to this rule. The vapor recovery efficiency is designed to achieve a minimum 95 percent control efficiency on a daily basis and 99.5 percent on a quarterly and annual basis. Compliance is monitored through implementation of the VRS Efficiency protocol.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). Per Section B.2, the APCD may require stationary sources that emit more than 5 lb/hr of non-methane hydrocarbons, oxides of nitrogen and sulfur oxides and more than 10 lb/hr of particulate matter. PXP is required to implement CEMS on the common stack to the cogeneration unit to monitor NO_x and CO emissions. An APCD approved CEMS Plan has been implemented and the CEMS are operating in compliance with that Plan.

Rule 330 - Surface Coating of Metal Parts and Products: This rule sets standards for many types of coatings applied to metal parts and products. In addition to the ROC standards, this rule sets operating standards for application of the coatings, labeling and recordkeeping. This rule only applies to metal parts and products which are not currently installed as appurtenances to the existing stationary structures. PXP is required to maintain records to verify compliance with this rule.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas processing plants. Ongoing compliance with the provisions of this rule will be assessed through facility inspection by APCD personnel (using an organic vapor analyzer) and through review of operator records.

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.. PXP The five turbine starter IC engines and emergency firewater pump each operate less than 200 hours per year and are therefore not subject to Sections D, E, F and G of the rule. Any temporary engine will be evaluated for applicability with permit and this rule's requirements at the time the engine is proposed for use.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rule limits NO_x emissions from external combustion units with a rated heat input greater than 5.0 MMBtu/hr to less than 30 ppmv (corrected to 3% O_2) when operated on gaseous fuel. In addition, carbon monoxide is limited to 400 ppmv (corrected to 3% O_2). PXP has five steam generators, each rated at 55 MMBtu/hr. Emissions are controlled through the use of anhydrous ammonia injection followed by Selective Catalytic Reduction. Annual source testing since 1988 has consistently demonstrated NO_x and CO emissions to be less than the requirements of this rule.

Rule 343 - Petroleum Storage Tank Degassing: This rule applies to the degassing of any above-ground tank, reservoir or other container of more than 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 2.6 psia, or between 20,000 gallons and 40,000 gallons capacity containing any organic liquid with a vapor pressure greater than 3.9 psia. Tanks T-1 and T-2 are subject to this rule. The use of VRS in conjunction with nitrogen sweep of each tank and implementation of the APCD approved Purging and Inerting Procedures Plan will ensure compliance with this rule.

Rule 344 - Petroleum Sumps Pits and Well Cellars: This rule applies to sumps, pits and well cellars at facilities where petroleum is produced, gathered, separated, processed or stored. Sump S-4 is subject to the APCD-approved S-4 Drain Sump Monitoring and Maintenance Plan.

Rule 353 - Adhesives and Sealants: This rule applies to the use of adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers. Compliance shall be based on site inspections.

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. The flare at this facility is subject to this rule. 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 239 ppmv calculated as H_2S at standard conditions. Sampling of flare gas is required.

§ D.2 - Technology Based Standard: Requires all flares and thermal oxidizers to be smokeless and sets pilot flame requirements. The flare is in compliance with this section as determined through APCD inspection.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. PXP has submitted and fully implemented their APCD approved Flare Minimization Plan.

Rule 505 - Breakdown Conditions: This rule describes the procedures that PXP must follow if they decide to apply for relief from enforcement action as provided by this rule. 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 APCD 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. PXP submitted an Emergency Episode Plan in June February 15, 2001.

3.5 Compliance History

This section contains a summary of the compliance history for this facility and was obtained from documentation contained in the APCD's Administrative files.

3.5.1 Facility Inspections. The GOHF is inspected by the APCD each calendar quarter. Since the previous permit renewal, with the exception of the enforcement actions documented below in section 3.5.2, each quarterly inspection indicates that the GOHF has operated in compliance with APCD rules, regulations and the permit conditions of this permit.

3.5.2 *Violations:* Since issuance of the last Part 70 permit renewal the following enforcement actions have been issued: Each has been resolved.

NOV No. 8456: Violation of Rule 206. Issued 01/11/06. Exceedance of BACT H2S limits in fuel gas.

NOV No. 8457: Violation of Rule 206. Issued 01/11/06. Exceedance of BACT H2S limits in fuel gas.

NOV No. 8466: Violation of Rule 206. Issued 06/22/06. Failure of annual RATA.

NOV No. 8473: Violation of Rule 505. Issued 11/14/06. Late submittal of a final Breakdown report.

3.5.3 Variances: There have been no significant variances issued for the GOHF since the last permit renewal.

Table 3.1 - Generic Federally-Enforceable APCD 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	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 of 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	Addition of new equipment of modification to existing

	applications.	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 304: PM Concentration – North Zone	Each PM source	Emission of PM in effluent gas
RULE 309: Specific Contaminants	All emission units	Combustion contaminants
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 Ops.

Table 3.1 Continued - Generic Federally-Enforceable APCD Rules

Generic Requirements	**Affected Emission Units**	**Basis for Applicability**
RULE 321: Solvent Cleaning Operations	Emission units using solvents	Solvent used in process operations.
RULE 322: Metal Surface Coating Thinner and Reducer	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.
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: 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	The Point Arguello Project PTE is greater than 100 tpy.
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	The Point Arguello Project is a major source.

Table 3.2 - Unit-Specific Federally-Enforceable APCD Rules

Unit-Specific Requirements	Affected Emission Units	Basis for Applicability
RULE 325: Crude Oil Production and Separation	EQ Nos: 4-1 thru 4-6	All pre-custody production and processing emission units
RULE 331: Fugitive Emissions Inspection & Maintenance	EQ Nos: n/a	Components emit fugitive ROCs.
RULE 342: Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters	EQ Nos: 1-1 thru 1-6	Rated greater than 5 MMBtu/hr
RULE 343: Petroleum Storage Tank Degassing	EQ Nos: n/a	Capacities greater than 40,000 gallons
RULE 359: Flares and Thermal Oxidizers	EQ Nos: 2-1	Used in petroleum service

Table 3.3 - Non-Federally-Enforceable APCD Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Odorous Org. Sulfides	All emission units	Emission of organic sulfides
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 limits are exceeded or rule requirements are not complied with.
RULES 506-519: Variance Rules	All emission units	Administrative

Table 3.4 – Adoption Dates of APCD Rules Applicable at Issuance of Permit

Rule No.	Rule Name	Adoption Date
Rule 101	Compliance by Existing Installations: Conflicts	June 1981
Rule 102	Definitions	May 20, 1999
Rule 103	Severability	October 23, 1978
Rule 201	Permits Required	April 17, 1997
Rule 202	Exemptions to Rule 201	April 17, 1997
Rule 203	Transfer	April 17, 1997

Rule No.	Rule Name	Adoption Date
Rule 204	Applications	April 17, 1997
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of Authority to Construct or PTO	October 15, 1991
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	Sept. 18, 1997
Rule 322	Metal Surface Coating Thinner and Reducer	October 23, 1978
Rule 323	Architectural Coatings	July 18, 1996
Rule 324	Disposal and Evaporation of Solvents	October 23, 1978
Rule 325	Crude Oil Production and Separation	January 25, 1994
Rule 326	Storage of Reactive Organic Compound Liquids	Dec. 14, 1993
Rule 328	Continuous Emissions Monitoring	October 23, 1978
Rule 331	Fugitive Emissions Inspection and Maintenance	Dec. 10, 1991
Rule 333	Control of Emissions from Reciprocating ICEs	April 17, 1997
Rule 342	Control of NOx from Boilers, Steam Generators and Process Heaters	April 17, 1997
Rule 343	Petroleum Storage Tank Degassing	Dec. 14, 1993
Rule 344	Petroleum Sumps, Pits and Well Cellars	Nov. 10, 1994
Rule 353	Adhesives and Sealants	August 19, 1999
Rule 359	Flares and Thermal Oxidizers	June 28, 1994

Rule No.	Rule Name	Adoption Date
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 901	New Source Performance Standards (NSPS)	May 16, 1996
Rule 903	Outer Continental Shelf (OCS) Regulations	Nov. 10, 1992
Rule 1001	Nat'l. Emission Stands. for Hazardous Air Pollutants (NESHAPS)	October 23, 1993
Rule 1301	General Information	Sept. 18, 1997
Rule 1302	Permit Application	November 9, 1993
Rule 1303	Permits	November 9, 1993
Rule 1304	Issuance, Renewal, Modification and Reopening	November 9, 1993
Rule 1305	Enforcement	November 9, 1993

4.0 Engineering Analysis

4.1 General

The APCD has confirmed that all emission sources are included in the emissions listings. In addition, process flow diagrams "PFDs" and piping and instrumentation drawings "P&IDs" were reviewed to ensure that all emission sources and appropriate instrumentation controls are included in the project's emissions and equipment inventory. This section provides detailed information on emission controls and calculations, source testing, process monitoring, sampling, meter calibration and continuous emission monitoring.

The APCD conducted a limited review of the project design for upset potential which could lead to excess emissions. An EIS/EIR analysis of the potential for upsets and the release of air pollutants was done. A number of major systems safety features and operations were included in PXP's project design. The project contains several key features to minimize the potential for flaring episodes and other excess emissions resulting from process upsets. These features include a vapor recovery system on the flare header to recycle vented vapors, a network of emergency controls and redundant systems (e.g., spare pumps and compressors for critical units).

4.2 External Combustion Equipment

Turbines. The cogeneration plant consists of five individual cogeneration units, operating in parallel, with the exhaust gases feeding into a common duct/stack. Each cogeneration unit consists of an Allison Model 501-KB turbine, with a rated firing capacity of 48.4 MMBtu/hr, driving a generator rated at 3.695 Megawatts (at the generator terminal). The turbines are fired on natural gas containing 4 ppm or less total sulfur. The cogeneration units are equipped with pre- and post-combustion emission controls. Pre-combustion controls include the injection of water into the combustion chamber at a minimum water to fuel ratio (mass basis) of 0.80:1.0. Water injection serves to lower the turbine combustion temperature, thus reducing NO_x formation by approximately 70 percent. Post-combustion controls include ammonia injection and Selective Catalytic Reduction in the common exhaust duct (as noted below, the SCR also receives the exhaust from the heat recovery steam generators and the SCR burner). Ammonia is injected immediately before the SCR unit at a NO_x to ammonia ratio (molar basis) of 1.1:1.0 ±10%. A distribution grid ensures thorough mixing of the ammonia with NO_x prior to entering the SCR. The SCR is a Zosen Model *NOX NON* 700. It is a "honeycomb" type, constructed of corrugated ceramic paper with titanium oxide as a carrier and vanadium oxide and tungsten oxide as the active catalyst material. The permit analysis assumes that this system is capable of achieving a NO_x reduction of 80 percent (mass basis). The calculation methodology, using controlled emission factors, for determining emissions from the cogeneration plant is as follows:

$$ER = \{[(E_t \times F_t) + (E_b \times F_b) + (E_s \times F_s)] \times HHV\} + D \times \{HHP\}$$

(Equation 4.2)

where:

ER	=	controlled emission rate (lbs/hr)
E_t	=	turbine pollutant specific emission factor (lb/MMBtu)
F_t	=	turbine fuel use (SCFH)
E_b	=	heat recovery steam generator pollutant specific emission factor (lb/MMBtu)
F_b	=	heat recovery steam generator fuel rate (SCFH)
E_s	=	SCR burner pollutant specific emission factor (lb/MMBtu)
F_s	=	SCR burner fuel rate (SCFH)
HHV	=	higher heating value (Btu/SCF)
D	=	diverter valve leakage rate (lbs NO_x/hr)
HHP	=	operating hours per time period (hrs/period)

The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1.

Fuel gas is provided to the entire cogeneration plant via a single six-inch line from the high pressure gas header. Fuel to each turbine/heat recovery steam generator is provided via three-inch lines and fuel to the SCR burner is supplied via a two-inch line. Fuel, water and ammonia feed rates are determined by the meters identified in PXP's APCD-approved *Process Monitor Calibration and Maintenance Plan.* Each meter is equipped with a transmitter for sending data to the monitoring system in the GOHF control room.

Heat Recovery Steam Generators. A heat recovery steam generator (HRSG) is located downstream of each turbine duct. The HRGS is custom manufactured by Struthers, equipped with Coen burners for PXP's application. The HRSG utilizes the heat of the turbine exhaust to produce steam, which is then piped to various plant operations via insulated piping. The HRSGs are equipped with supplementary burners, which can be fired to produce additional steam if operational heat demands cannot be met through recovery of heat from the turbines. The supplemental burners are fired on PUC quality natural gas and are rated at 54.78 MMBtu/hr each. The HRSG exhaust commingles in the common exhaust duct for all five turbines. The common exhaust duct is also equipped with a non-fired heat recovery steam generator which recovers additional heat from the exhaust to pre-heat the water/steam before the exhaust enters the NO_x emission control unit.

The emission calculation methodology is based on Equation 4.2 above. The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1.

SCR Duct Burner. The SCR unit is equipped with a burner rated at 60.5 MMBtu/hr manufactured by Entec, however PXP has opted to operate this burner at no more than 49.5 MMBtu/hr. This duct burner is used to maintain the catalyst bed at optimum operating temperatures (550°F to 750°F). The SCR is capable of reducing NO_x emissions by 80 percent. The SCR unit is designed to control the exhaust flow of all turbines/HRSGs and the SCR duct burner simultaneously.

The emission calculation methodology is based on Equation 4.2 above. The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1.

4.3 Piston Internal Combustion Engines.

The diesel starter engine starts the turbine spinning, whereby the turbine begins drawing air, which purges the exhaust duct of potential hydrocarbons. Once the purging is completed, fuel is introduced to the turbine and ignition is attempted. Each of the five turbine generators is equipped with a Detroit Diesel Model 4-53-T turbocharged, diesel-fired starter engine rated at 185 bhp. In addition, GOHF has one emergency firewater pump driven by a diesel fired engine manufactured by Caterpillar Model 3306 and is rated at 267 bhp. The calculation methodology for the diesel fired engines is as follows:

$$ER = EF \times BHP \times BSFC \times LCF \times HPP$$

where:

ER	=	emissions rate (lbs/period)
EF	=	pollutant specific emission factor (lb/MMBtu)
BHP	=	engine rated max brake-horsepower (bhp)
BSFC	=	engine brake specific fuel consumption (Btu/bhp-hr)
HPP	=	operating hours per time period (hrs/period)

The emission factor is an energy based value using the higher heating value ("HHV"). As such, an energy based BSFC value must also use the HHV. For diesel fuel oil, the HHV value is typically 6 percent greater than the corresponding LHV data. Each engine is equipped with an elapsed hour meter. The starter engines and firewater pump operate less than 200 hours per year.

The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1.

4.4 Fugitive Hydrocarbon Sources

Fugitive hydrocarbon emissions are due to leaks from process components such as valves, connections, pumps, compressors and pressure relief devices. Each of these component types may be comprised of several potential "leak paths" at the facility. For example, leak paths associated with a valve include the valve stem, bonnet and the upstream and downstream flanges. The total number of leak paths at the facility must be determined to perform fugitive emission calculations. Calculations for determining fugitive hydrocarbon emissions are as follows:

$$ER = EF \times CLP \times (1 - CE) \times HPP$$

where:

ER	=	emission rate (ROC lb/period)
CLP	=	number of category/service-specific leak paths
EF	=	leak path-specific emission factor (lb/clp-day)
CE	=	control efficiency
HPP	=	hours per period

An overall emission reduction efficiency of about 80 percent is achieved as a result of PXP's implementation of an Inspection and Maintenance ("I&M") program which is considered BACT. The control efficiency for valves is 84 percent due to PXP's monitoring of these components on a monthly basis. The I&M program is designed to minimize leaks through a combination of pre- and post-leak controls. Pre-leak controls include venting of leaks from compressor seals to the vapor recovery system, use of dual mechanical seals on pumps in light liquid service, venting of pressure relief devices to the flare system, and plugging of open-ended lines (an open-ended line is a valve that has one side of the valve seat in contact with the process fluid, and is open to the atmosphere on the other). Post-leak controls consist of regular inspection of each leak source for leakage and repair of all components found leaking. Inspections are performed with an Organic Vapor Analyzer consistent with EPA Method 21. Components are required to be repaired between 1 to 14 days, depending on the severity of the leak. PXP's I&M program is consistent with the most stringent requirements of APCD Rule 331. PXP's I&M program also includes a leak path identification system. Leak paths are physically identified in the field with a "tag" and given a unique number. An inventory of each tag is then maintained which describes the component type, service, accessibility and all associated leak paths. The leak path inventory serves as a basis for compliance with fugitive hydrocarbon emission limits. Table 4.2 summarizes the requirements for the I&M Program.

4.5 Flare Relief System

The GOHF flare relief system consists of both high and low pressure headers that connect various PSVs and manual block valves to a common flare. The flare is also equipped with two water seals to minimize emissions.

Vapor Recovery Unit. The VRU collects vapors from all in-service tanks in the oil plant. The system utilizes two (2), 100% compressors (K-3 & K-3A) with multiple alarms. The VRU header pressure is maintained at about 1.5" water column by the K-3 VRU compressor and fuel gas makeup set at 1.2"water column. Vapor collected by K-3 is routed through the K-24 VRU flow meter to measure daily gas throughput in order to calculate the VRU efficiency required by the VRU Protocol. The K-3 discharge is routed to the flare header where it remains until the flare header pressure exceeds that of the water seal (21"w.c.). The vapor recovery system has a short-term (daily) efficiency of 95 percent and a long-term (quarterly and annual) efficiency of 99.5 percent, both on a mass basis. Monitoring of the VRU efficiency is confirmed through implementation of the VRU Protocol.

Water Seals. At the flare stack, two water seals provide a seal between the atmosphere and the flare header and up to 21-inches of water column back pressure for the vapor recovery compressor. In the event of a flow to the flare which is in excess of the vapor recovery compressor capacity, the water seal is lost and flow proceeds to the flare for incineration. If the excess volume is relatively small, flow proceeds through a six-inch water filled line bypassing the main water seal. This line is equipped with its own flow meter. This allows for metering of low flow flare events. For large events which exceed the capacity of the six-inch line, flow proceeds through the main water seal. As a safety precaution during periods of no flare gas flow, purge gas is introduced into the flare stack downstream of the water seals to prevent air ingress into the flare stack and sweep gases in the flare header towards the vapor recovery compressor. As discussed above in section 2.1.4, during chemical injection, the water seal in the six-inch line is not required to be in tact.

The flare is manufactured by Peabody Engineering and is rated at about one million pounds of hydrocarbons an hour. It is equipped with steam injection to reduce visible emissions (smoke). This flare type has a molecular sieve to ensure air does not enter the stack during periods of low flow.

Emissions. Flaring emissions associated the controlled shutdown of GOHF for maintenance and inspection as well as the planned continuous flaring from the VRU discharge are included in the emissions. Emissions for generic planned and unplanned "infrequent" have been calculated. The calculation for determining flare emissions is as follows:

$$ER = EF \times FR \times HVC$$

where:

ER	=	emission rate (lb/period)
EF	=	pollutant specific emission factor (lb/MMBtu of vented gas)
FR	=	flare header flow rate (Btu/period)
HVC	=	heating value correction (average heating value of flare gas (Btu/scf) divided by 1050 Btu/scf).

The emission factors for NO_x, ROC, CO and PM are based on a heating value of 1200 Btu/scf. The heating value correction factor is used for the NO_x, ROC, CO and PM factors to account for flaring of gases with different heating values. The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1.

PXP has implemented an APCD-approved purging plan for the degassing or purging of stationary tanks and vessels. Vessels are required to be depressurized to a downstream area of GOHF until the pressures equalize. Liquids are to be pumped to other appropriate storage vessels. Residual vapors are then swept to the flare header.

4.6 Tanks/Sumps/Separators

All tanks located at the GOHF are welded with fixed roof tanks. Emissions from the tanks are due to fugitive emissions and evaporative losses.

Tanks (T-1 and T-2): The detailed tank calculations for compliance is performed using the methods presented in USEPA AP-42, Chapter 7. The emission factors for each pollutant are listed in Table 5.2-2. The derivation and basis for these factors is provided in Attachment 10.1. The emission spreadsheets are provided in Attachment 10.2. Note that during this permit renewal a correction was made to the T-2 tank calculation. The tank "annual throughput - gal" variable, erroneously listed as 5.04E+07, was corrected to 5.04E+08. This resulted in a 1.2 tpy increase in ROC emissions, however, these do not constitute NEI.

Tanks (T-4, T-8, T-25): Tanks T-4 and T-25 are classified as secondary production and heavy oil service. Tank T-8 is classified as tertiary production and heavy oil service. Emission calculations are based on surface area of emissions unit as supplied by the applicant. The calculation is:

$$ER = \left[EF \times SA \times (1 - CE) \times HPP\right]$$

where:

ER	=	emission rate (ROC lb/period)
EF	=	ROC emission factor (lb/ft^2-period)

SA	=	surface area (ft^2)
CE	=	control efficiency
HPP	=	hours per period

4.7 Other Emission Sources

General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurring as part of normal daily operations and includes cold solvent degreasing and wipe cleaning. Emissions are determined based on mass balance assuming that all the solvent used evaporates to the atmosphere.

Surface Coating: Surface coating operations typically include normal touch up activities. Emissions are determined based on mass balance calculations assuming all solvents evaporate into the atmosphere. Emission of PM/PM_{10} from paint overspray are not calculated due to the lack of established calculation techniques

Abrasive Blasting: Abrasive blasting with CARB certified sands may be performed as a preparation step prior to surface coating. The engines used to power the compressor are not subject to this permit (PXP or the engine operator is responsible for engine compliance prior to the time of use). 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}. A PM/PM_{10} ratio of 1.0 is assumed.

4.8 BACT/NSPS/NESHAP/MACT

BACT: The net emissions increase ("NEI") for the Project triggered requirements for implementation of Best Available Control Technology ("BACT") for NOx, ROC, CO, SO_x and PM. The original BACT determination was made in 1986 and thus reflects the best available controls available at that time. Table 4.1 summarizes the BACT measures applicable to the GOHF.

Pursuant to APCD Policy and Procedure 6100.064, once an emission unit is subject to BACT requirements, then any subsequent modifications to that emissions unit or process is subject to BACT. This applies to both *de minimis* changes and equivalent replacements, regardless of whether or not such changes or replacements require a permit.

Rule 331 BACT Determinations: Pursuant to Sections D.4 and E.1.b of Rule 331, critical components are required to be replaced with BACT (or District-approved alternate BACT) in accordance with the APCD's NSR rule. These determinations are based on a case-by-case basis following the APCD's guidance document for determining BACT due to Rule 331.

NSPS: Discussion of applicability and compliance with New Source Performance Standards is presented in Section 3 of this permit. An engineering analysis for the affected equipment is found in the sections above.

NESHAP: PXP has not identified any equipment or processes that are subject to an applicable National Emission Standard for Hazardous Air Pollutants.

MACT: A National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage was promulgated on June 17, 1999. A black oil exemption from this MACT was approved by the APCD on October 25, 2000. Maintaining the exemption requires specific recordkeeping requirements. See permit condition 9.B.13.

4.9 Process Monitoring

Continuous Monitoring: The APCD reviewed the project P&ID's to determine the emission sources that need continuous monitoring to ensure permit compliance. These requirements were revised following GOHF modifications discussed above. Table 4.3 identifies the parameters that currently require continuous monitoring. In order for the APCD to assess facility operation status and to ensure major emission sources are operating properly, selected monitored data is telemetered to the Data Acquisition System ("DAS") at the APCD's office on a real-time basis. The data required to be telemetered is also identified in this table.

The monitoring devices described must meet the requirements set forth in APCD Rule 328 and in 40 CFR Part 51 and Part 60. Process parameter monitors shall be maintained and calibrated consistent with applicable CFR or APCD regulations and manufacturer's specifications. PXP's APCD-approved CEM Plan specifies the analyzer types, operating procedures, computer software and hardware, emission calculations, maintenance and calibration, and recordkeeping and reporting requirements.

Additional continuous monitors or redundant systems may be required by the APCD if problems with facility or monitor operations develop which warrant additional monitoring.

Table 4.1
PXP Gaviota - PTO 5704
Summary of BACT Measures

Source	Pollutant				
	ROC	NO_x	SO_x	CO	PM/PM_{10}
Gas Turbines	Use of pipeline quality gas as fuel; proper combustor operation	Water injection (70% control) on individual turbines plus SCR (80% control) on combined exhaust	Use of pipeline quality gas as fuel; 4 ppmv H_2S maximum	Use of pipeline quality natural gas as fuel; proper combustor operation	Use of pipeline quality gas as fuel; proper combustor operation
Auxiliary Heaters	Use of pipeline quality gas as fuel; proper burner operation	Low NO_x burner design plus SCR (80% control)	Use of pipeline quality gas as fuel; 4 ppmv H_2S maximum	Use of pipeline quality natural gas as fuel, proper burner operation	Use of pipeline quality gas as fuel, proper burner operation
Fixed Roof Crude, Wastewater, Oil/Water Processing	Vapor Recovery - 95% short term and 99.5% long term.	-	-	-	-
Flare	Proper burner management and monitoring; gas-fired pilots	Proper burner management and monitoring; gas-fired pilots; emissions equivalent of Thermal Oxidizer	Gas-fired pilots; pilot fuel with 4 ppmv H_2S maximum	Proper burner management and monitoring; gas-fired pilots	Gas-fired pilots; steam injection for smokeless operation

Table 4.1 (continued)
PXP Gaviota - PTO 5704
Summary of BACT Measures

Source	Pollutant				
	ROC	NO_x	SO_x	CO	PM/PM_{10}
Fugitive ROC	Inspection and maintenance (I&M) program for all onshore facilities, pressure relief devices in HC service vented to vapor control system; compressor seals in HC service vented to vapor control systems; dual mechanical or tandem pump seals for gaseous and light liquid streams; single mechanical pump seals for heavy liquid streams; closed purge sampling systems for gaseous and light liquid streams; no open-ended lines; monthly monitoring of valves; fin-fan cooler plugs kept at NDE condition; enhanced component tagging system.	-	-	-	-
Vacuum Truck Usage	Use of carbon canister or VRU system	-	Venting of exhaust through caustic scrubber for H_2S control or VRU system	-	-
Depressuring of Vessels	Depressure to vapor control system and purge with pipeline quality gas	-	After depressuring, venting of exhaust through caustic scrubber for H_2S control	-	-

Notes: Pipeline quality gas is gas meeting the pipeline quality requirements established by the State Public Utilities Commission. See Table 4.2 for required ROC Inspection and Maintenance Program.

TABLE 4.2
PXP GAVIOTA - PTO 5704
FUGITIVE HYDROCARBON INSPECTION AND MAINTENANCE (I&M) PROGRAM

	GAS COMPONENTS[a]	OIL COMPONENTS[b]
Leak Definition	Gaseous: 10,000 ppm[c] Liquid: any indication	Gaseous: 10,000 ppm[e] Liquid: any indication
Valve Monitoring[f,g]	Monthly	Monthly
Relief Valve Monitoring[r]	Vented to flare	Vented to flare
Pump Monitoring	Dual Seals[k]	Monthly
Connections Monitoring[h,i,j,s]	Quarterly	Quarterly
Open-Ended Lines	Capped	Capped
Compressors	Vented to vapor control system	Not applicable
Repair Requirements[m,n,o]	First attempt within 5 days. Repair within 15 days. Also see Rule 331 requirements.	First attempt within 5 days. Repair within 15 days. Also see Rule 331 requirements.
Record Keeping and Reporting Requirements	See Rule 331 requirements.	See Rule 331 requirements.

Table 4.2 Notes:

a Applicable to equipment in VOC service (that is, contains or contacts a process fluid that is at least 10 percent VOC by weight at 150°C) or in wet gas service (that is, contains or contacts inlet gas before GOHF extraction process).

b Applicable to oil components in heavy hydrocarbon Liquid service (that is, contains or contacts a process fluid that is less than 10 percent VOC by weight at 150°C).

c Gas Components Leak Detection
Gaseous and Light hydrocarbon Liquid component Leakage monitoring will be determined by a hydrocarbon analyzer which uses the flame ionization detection method, and additionally by visual inspection.

d Calibration of the hydrocarbon analyzer will be similar to NSPS requirements.

e Heavy Hydrocarbon Liquid Leak Detection
Heavy hydrocarbon liquid component leakage monitoring will be determined by visual inspection. Monitoring with a hydrocarbon analyzer may be required.

f Valves
Reductions in fugitive emissions due to the implementation of the APCD I&M Programs assume that all valves are accessible to monthly/quarterly monitoring.

g The monthly/quarterly valve monitoring program required by the APCD is similar to that of the NSPS valve monitoring program.

h Connections
The same record keeping and reporting procedures as NSPS are also required for connections; alternatively, a procedure approved by the Air Pollution Control Officer can be used. It is assumed that the total connection count includes all connections required for the venting of relief valves to a vapor control system, the capping of open-ended lines, and the conversion of sampling to a closed purge system.

j Leak detection for connections in gaseous and light hydrocarbon liquid service will utilize measurement enhancement techniques if determined to be necessary by the APCD.

k Pumps
The APCD I&M program on pumps with dual seals is similar to that required by NSPS on pumps with dual seals.

l Compressors
The APCD fugitive emissions calculation assumes no emissions from compressor seals which are required by BACT to be vented to a vapor control system. The APCD assumes that a leak detection program around the compressors will be part of the I&M program to insure that the vent system is operating properly and that no emissions from the compressors are occurring.

m Repair Requirements
Repair requirements are similar to NSPS. Also see Rule 331.

n It is assumed that spare parts and maintenance personnel are available when necessary for repair.

o Emissions reduction credit will not be applicable to leaking components that are not repaired within the requirements of this program. For repairs made at process turnarounds, emissions reduction credit will be based on the statistical frequency of process turnarounds or shutdowns.

p Record Keeping and Reporting Requirements
Record keeping and reporting requirements are similar to the most stringent of NSPS requirements. Also see Rule 331.

q Component Accessibility
Consistent with NSPS, all component shall be accessible to leak detection monitoring where feasible. Access to components above ground level shall be maximized through the use of ladders, elevated platforms, manlifts, or other appropriate devices. Emissions reduction credit will be adjusted based on component accessibility.

All continuously monitored parameters must be recorded on backup strip chart recorders unless this requirement is waived by the APCD. The required data will be consolidated and submitted to the APCD as required by Section 9.C. More frequent reporting may be required if the APCD deems this necessary. Minimum data reporting requirements must include the following:

- o Summary of monitor downtime, including explanation and corrective action; and
- o Report on compliance with permit requirements, including any corrective action being taken.

Operator log entries, strip charts, and/or magnetic tapes or discs must be provided upon request by the APCD.

Table 4.3
PXP Gaviota – PTO 5704
Parameters To Be Continuously Monitored

Gas Turbines/Auxiliary Heaters With SCR And Single Stack	Elevated Flare	Oil and Gas Processing	
NO_x - inlet to SCR system in common stack[6,7]	Exhaust Flow and O_2 concentration[5]	Flare gas flow rate[1,2a,6,7]	Volume of oil processed in KBOD[6,7]
NO_x - outlet from SCR system (ppmv@ 3% O_2)[1,5,6]		Pilot temperature[2]	Tank Vapor Recovery System Header Pressure[2,6]
NO_x - outlet from SCR system (lb/hr)[1,5,6]		Pilot and purge gas flow rate[6,7]	Tank vapor recovery system PRV position indicator status[(2,6)]
CO - outlet from SCR system (lb/hr)[1,6]		Steam flow rate	
NH_3 - outlet from SCR system[3]		Flare Gas H_2S concentration by Dreager Tube[7,9]	
SOx - Facility Fuel In-line continuous analyzer [2a, 6]			
Fuel feed rate - to each turbine and auxiliary heater[6,7,8]			
NH_3 feed rate to SCR system[2b,6]			
Fuel feed rate to SCR [6,7]			
Fuel Gas H_2S Content [1,5]			
Exhaust gas temperature - inlet[(2,6)] and outlet to SCR system; downstream of each turbine's auxiliary heater			
Water injection rate to each turbine[2b,6]			

Table 4.3 Notes:

(1) Parameters to be telemetered.
(2) a. Equipped with High in plant alarm.
    b. Equipped with Hi/Low in plant alarm.
(3) Continuous monitoring of these parameters is not required initially. However, the APCD may request that monitors for these parameters be installed in the future.
(4) n/a.
(5) Equipped with high alarm telemetered to the APCD.
(6) Permanent recording of parameter raw data required via strip-chart, circular chart, or computer printout.
(7) Parameters to be included in semi-annual reports. The APCD may request additional information be presented in these reports if necessary.
(8) Fuel use for this equipment shall be provided in a District-approved format such that compliance with equipment operational limits can be determined.
(9) Parameter to be recorded in a log.

4.10 Source Testing/Sampling/Monitoring/Meter Calibration

Source testing, sampling, monitoring and meter calibration are required in order to ensure compliance with permitted emission limits, Prohibitory rules, NSPS, control measures and the assumptions that form the basis of this operating permit.

Source Testing. PXP is required to follow the APCD Source Test Procedures Manual (May 24, 1990 and all subsequently approved updates). The parameters to be source tested annually at the onshore facility are identified in Table 4.4. The APCD may require additional source testing if problems develop or if unique circumstances occur that warrant special testing. Only the Cogeneration Plant is required to be source tested. Source testing requirements are addressed in condition 9.C.15.

Sampling. At a minimum, the process stream below is required to be sampled and analyzed on a quarterly basis (except where noted). Unless otherwise indicated, duplicate samples are required:

→ Fuel Gas: Sample taken at the fuel gas header. Analysis for: total sulfur, H_2S and HHV.

As necessary to ensure compliance with this permit and applicable rule and regulations, the APCD may require PXP, by written notice, to sample additional process streams in a manner and frequency specified by the APCD. All sampling and analyses are required to be performed according to APCD-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 GOHF source test plan shall include the sampling and analytical methods required to obtain the process stream data stated above.

Monitoring. In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the used of process monitoring systems. Examples of these monitors include: engine hour meters, fuel usage meters, water injection mass flow meters, flare gas flow meters and hydrogen sulfide analyzers. 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:

- → turbine fuel gas meters
- → turbine water injection meters
- → SCR ammonia injection meters
- → HRSG fuel gas meters
- → cogeneration plant kilowatt-hour meters
- → fuel gas meters
- → flare header flow meters
- → hour meters (turbine starter engines, firewater pump)
- → production meters (wet oil treated, dry oil produced,
- → fuel gas H_2S analyzer

As necessary to ensure compliance with this permit and applicable rule and regulations, the APCD may require PXP, by written notice, to install additional process monitors. Further, the APCD may require PXP, by written notice, to expand the list of existing plant process monitors detailed in the list above.

Meter Calibration. PXP is required to maintain GOHF meters in accordance with the Process Monitor Calibration and Maintenance Plan. This Plan takes into consideration manufacturer recommended maintenance and calibration schedules and may include other accuracy checks. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment are to be utilized.

Table 4.4
PXP Gaviota - PTO 5704
Source Test Requirements

Pollutants/ Emission Point	Parameters	Test Methods
COGEN PLANT		
- Catalyst Outlet	NO_x (ppmv, lb/hr)	EPA Method 7E & Method 20
	NH_3 (ppmv, lb/hr)	BAAQMD ST-1B
	CO (ppmv, lb/hr)	EPA Method 10
	THC/ROC (ppmv, lb/hr)	EPA Method 18
	PM (gr/dscf, lb/hr)	EPA Method 5
	O_2	EPA Method 3
	Velocity	EPA Method 2
	Temperature	thermocouple
	Moisture	EPA Method 4
-Turbine Bypass Stack[C]	NO_x (ppmv, lb/hr)	EPA Method 7E & Method 20
	O_2	EPA Method 3
	Velocity	EPA Method 2 or alternative
	Temperature	thermocouple
	Moisture (optional)	EPA Method 4 or alternative
- Process Data	temperature at catalyst inlet	thermocouple
	HRSG fuel usage	plant meter
	turbine fuel usage	plant meter
	duct burner fuel usage	plant meter
	fuel gas composition/HHV	ASTM
	Fuel gas total sulfur content	ASTM
	turbine water injection rate	plant meter
	ammonia injection rate	plant meter
	catalyst pressure drop	magnehelic
	steam production rate	plant meter
	ambient temperature, pressure	thermocouple, barometer

Site Specific Requirements

a. All annual cogeneration plant emissions tests are to consist of three 40-minute runs. A minimum of two turbines shall be tested at maximum safe load. Source testing of one of the turbines will be performed with the HRSG burner on if a burner has been operated in the previous year. If more that one burner was operated simultaneously in the previous year, then testing of the turbines with more than one burner one is required. Notwithstanding the above, PXP may request, in writing, APCD written approval to test alternatives to the requirements above.

b. USEPA methods 1-4 to be used to determine O_2, dry MW, moisture content, CO_2 and stack flow rate.

c. Annual testing of bypass stack leakage is required for compliance with 9.C.1 (a) (iv). Such testing is done during normal flow out the SCR/main stack. If the turbine being tested unexpectedly shuts down during the bypass test, all the turbine flow may be directed out the main stack, and PXP shall not be in violation during this time. This allowance is made for safety reasons to avoid a blow out of the bypass stack extender used during the test.

d. PM testing is required only upon request by the APCD.

5.0 Emissions

5.1 General

Emissions calculations are divided into "permitted" and "exempt" categories. All emission sources are included in the potential-to-emit calculations. Permit exempt equipment is determined by APCD Rule 202. Total emission limits for the entire Project are summarized in Table 5.1. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit. 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 federal potential to emit calculation using the definition of potential to emit used in Rule 1301.

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})

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. Table 5.2-1 provides the basic operating characteristics. Table 5.2-2 provides the specific emission factors. Tables 5.2-3 and 5.2-4 shows the permitted short-term and permitted long-term emissions for each unit or operation. In the table, the last column indicates whether the emission limits are federally enforceable. Those emissions limits that are federally enforceable are indicated

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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

by the symbol “FE”.

5.3 Permitted Emission Limits - Facility Totals

The total potential-to-emit for all 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 5.2-1 for each emission unit are assumed. Table 5.3 shows the total permitted emissions for the facility.

Hourly/Daily Scenario

Peak hourly and daily emissions were based on the following equipment operating assumptions:

→ 3 Turbine generators operating at maximum rating (14.78 MW, 193.6 MMBtu/hr)
→ 2 Heat recovery steam generators operating at maximum rating (164.34 MMBtu/hr)
→ 1-SCR duct burner operating at a reduced federally enforceable rating (49.50 MMBtu/hr)
→ 1 emergency firewater pump
→ Flare pilot and purge rates operating at maximum rating (1,200 scfh)
→ Infrequent flaring do not exceed four events per equipment item
→ Fugitive ROC emissions based on maximum permitted component counts
→ A crew boat operating within state waters (from the Gaviota Pier)
→ Oil storage tanks and wastewater tanks in use at permitted throughputs
→ Solvent use for wipe cleaning and cold solvent degreasing (monthly average based on eight hour day)

Quarterly and Annual Scenario:

→ 3-Turbine generators operating at maximum rating (8760 hrs/yr)
→ 2-Heat recovery steam generators operating at maximum rating (8760 hrs/yr)
→ 1-SCR duct burner operating at a reduced federally enforceable rating (8760 hrs/yr)
→ 1 emergency firewater pump
→ Flare pilot and purge rates operating at maximum rating (8760 hrs/yr)
→ Infrequent flaring and Plant failures at permitted levels
→ Fugitive ROC emissions based on maximum permitted component counts
→ A crew boat operating within state waters (8 trips per year from the Gaviota Pier)
→ Oil shipping and storage tanks and wastewater separators and storage tanks in use at permitted throughputs

→ Solvent use for wipe cleaning and cold solvent degreasing (monthly average based on eight hour day)

5.4 Part 70: Federal Potential to Emit for the Facility

Table 5.4 lists the federal Part 70 potential to emit. Being a NSR source, all project emissions, except fugitive emissions, which are not subject to any applicable NSPS or NESHAP requirement, are included in the federal definition of potential to emit.

5.5 Exempt Emission Sources/Part 70 Insignificant Emissions

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Exempt units such as maintenance operations using paints and coatings, contribute to the facility emissions. Table 5.4 lists these exempt emissions units and the expected emissions. These are emission estimates only. They are not limitations.

5.6 Net Emissions Increase Calculation

The NEI for the facility source is shown in Table 5.3. The NEI for the Point Arguello Stationary Source is shown below.

Stationary Source Net Emission Increase Since 1990 (FNEI-90)

Facility	NO_x	ROC	CO	SO_x	TSP	PM_{10}
GOHF						
lbs/day	209.29	376.65	455.55	8.66	70.69	70.69
tons/year	36.01	51.48	91.91	3.92	13.11	13.11
Platform Harvest						
lbs/day		1.94		1.19		
tons/year		0.32		0.22		
Platform Hermosa						
lbs/day	0.71	6.37	62.88	0.72	0.21	0.21
tons/year	0.13	1.02	8.14	0.13	0.04	0.04
Platform Hidalgo						
lbs/day	14.48	1.24	64.32	3.94	1.04	1.01
tons/year			7.44	4.45		
Total						
lbs/day	224.48	386.20	582.75	14.51	70.73	70.73
tons/year	36.14	52.82	107.49	8.72	13.15	13.15

Table 5.2-1
Operating Equipment Description
PTO No. 5704

		Device Specifications				Usage Data			Maximum Load Schedule				
Equipment Category	**Emissions Unit**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**	**References**
Combustion - Turbines	Turbine G-10A	NG	0.0004	3.695	MW	48.400	MMBtu/hr	--	1	24	2190	8760	A
	Turbine G-10B	NG	0.0004	3.695	MW	48.400	MMBtu/hr	--	1	24	2190	8760	
	Turbine G-10C	NG	0.0004	3.695	MW	48.400	MMBtu/hr	--	1	24	2190	8760	
	Turbine G-10D	NG	0.0004	3.695	MW	48.400	MMBtu/hr	--	1	24	2190	8760	
	Turbine G-10E	NG	0.0004	3.695	MW	48.400	MMBtu/hr	--	1	24	2190	8760	
	Diverter Valve Leakage	--	--	--	--	1.000	% of Exh.	--	1	24	2190	8760	
Combustion - External	HRSG G-10A	NG	0.0004	54.78	MMBtu/hr	54.780	MMBtu/hr	--	1	24	2190	8760	B
	HRSG G-10B	NG	0.0004	54.78	MMBtu/hr	54.780	MMBtu/hr	--	1	24	2190	8760	
	HRSG G-10C	NG	0.0004	54.78	MMBtu/hr	54.780	MMBtu/hr	--	1	24	2190	8760	
	HRSG G-10D	NG	0.0004	54.78	MMBtu/hr	54.780	MMBtu/hr	--	1	24	2190	8760	
	HRSG G-10E	NG	0.0004	54.78	MMBtu/hr	54.780	MMBtu/hr	--	1	24	2190	8760	
	SCR Burner	NG	0.0004	60.50	MMBtu/hr	49.500	MMBtu/hr	--	1	24	2190	8760	
Combustion - Flare													
Planned:	Pilot/Purge	NG	0.0004	1,200	scfh	1.320	MMBtu/hr	--	1	24	2190	8760	D
	Continuous	PG	0.0238	10.000	mmscf/yr	11,000	MMBtu/yr		--	--	0.25	1	
	Infrequent	PG	0.0238	5.000	mmscf/yr	6,000	MMBtu/yr	--	--	--	0.25	1	
	Oil Plant Shutdown	PG	0.0160	0.170	mmscf/evt	204	MMBtu/evt	--	--	--	1	4	
Unplanned:	Infrequent - Sour	SG	0.5060	4.000	mmscf/yr	4,800	MMBtu/yr	--	--	--	0.25	1.0	D
	Infrequent	PG	0.0238	25.000	mmscf/yr	30,000	MMBtu/yr	--	--	--	0.25	1.0	
Fugitive Components	Oil, valve, controlled	--	--	596	clp	--	--	--	1	24	2190	8760	E
	Oil, valve, UTM	--	--	15	clp	--	--	--	1	24	2190	8760	
	Oil, connection, controllec	--	--	2,648	clp	--	--	--	1	24	2190	8760	
	Oil, connection, UTM	--	--	60	clp	--	--	--	1	24	2190	8760	
	Oil, Seal, dual	--	--	6	clp	--	--	--	1	24	2190	8760	
	Oil, PRV, controlled	--	--	5	clp	--	--	--	1	24	2190	8760	
	Gas, valve, controlled	--	--	1,088	clp	--	--	--	1	24	2190	8760	
	Gas, valve, UTM	--	--	20	clp	--	--	--	1	24	2190	8760	

Table 5.2-1
Operating Equipment Description
PTO No. 5704

		Device Specifications				Usage Data			Maximum Load Schedule				
Equipment Category	**Emissions Unit**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**	**References**
Fugitive Components - cont	Gas, valve, NDE	--	--	295	clp	--	--	--	1	24	2190	8760	
	Gas, Connection, Cont.	--	--	4672	clp	--	--	--	1	24	2190	8760	
	Gas, Connection, UTM	--	--	84	clp	--	--	--	1	24	2190	8760	
	Gas, Connection, NDE	--	--	1140	clp	--	--	--	1	24	2190	8760	
	Gas, seals, controlled	--	--	0	clp	--	--	--	1	24	2190	8760	
	Gas, seals, dual	--	--	7	clp	--	--	--	1	24	2190	8760	
	Gas, PRV, controlled	--	--	3	clp	--	--	--	1	24	2190	8760	
	Gas, PRV, UTM	--	--	0	clp	--	--	--	1	24	2190	8760	
	Gas, PRV to flare	--	--	16	clp	--	--	--	1	24	2190	8760	
	Gas, PRV, tanks	--	--	8	clp	--	--	--	1	24	2190	8760	
Crew Boats, Controlled	Main Eng, Cruise	D2	0.2	816	Bhp - total	0.055	gal/hp-hr	0.20	1	2	4	16	F
	Auxiliary Eng	D2	0.2	168	Bhp - total	0.055	gal/hp-hr	0.50	1	2	4	16	
Tanks and Separators	Dry Oil (T-1)	--	--	100.0	1000 bbl/day	--	--	--	1	24	91	365	G
	Reject Oil (T-2)	--	--	120.0	1000 bbl/day	--	--	--	1	24	91	365	
	Wastewater (T-4)	--	--	1,174	ft2	--	--	--	1	24	91	365	
	Wastewater (T-8)	--	--	103	ft2	--	--	--	1	24	91	365	
	Wastewater (T-25)	--	--	908	ft2	--	--	--	1	24	91	365	
Combustion - Engines	Turbine Starter G-10A	D2	0.05	185	bhp	7000	Btu/bhp-hr	--	1.00	1.00	10	10	H
	Turbine Starter G-10B	D2	0.05	185	bhp	7000	Btu/bhp-hr	--	1.00	1.00	10	10	
	Turbine Starter G-10C	D2	0.05	185	bhp	7000	Btu/bhp-hr	--	1.00	1.00	10	10	
	Turbine Starter G-10D	D2	0.05	185	bhp	7000	Btu/bhp-hr	--	1.00	1.00	10	10	
	Turbine Starter G-10E	D2	0.05	185	bhp	7000	Btu/bhp-hr	--	1.00	1.00	10	10	
Solvent Usage	Cleaning/degreasing			650	gal/yr	--	--	--	0.33	1	0.25	1	I

Equipment Category	Emissions Unit	NOx lbs/hr	NOx lbs/day	ROC lbs/hr	ROC lbs/day	CO lbs/hr	CO lbs/day	SOx lbs/hr	SOx lbs/day	PM lbs/hr	PM lbs/day	PM10 lbs/hr	PM10 lbs/day	Federally Enforceable
Combustion - Turbines	Turbine G-10A	1.40	33.6	0.40	9.6	4.50	108.0	0.07	1.8	0.55	13.2	0.55	13.20	FE
	Turbine G-10B	1.40	33.6	0.40	9.6	4.50	108.0	0.07	1.8	0.55	13.2	0.55	13.20	FE
	Turbine G-10C	1.40	33.6	0.40	9.6	4.50	108.0	0.07	1.8	0.55	13.2	0.55	13.20	FE
	Turbine G-10D	1.40	33.6	0.40	9.6	4.50	108.0	0.07	1.8	0.55	13.2	0.55	13.20	FE
	Turbine G-10E	1.40	33.6	0.40	9.6	4.50	108.0	0.07	1.8	0.55	13.2	0.55	13.20	FE
	Diverter Valve Leakage	0.32	7.7	--	--	--	--	--	--	--	--	--	--	
Combustion - External	HRSG G-10A	1.10	26.3	0.61	14.7	1.64	39.4	0.03	0.8	0.40	9.7	0.40	9.66	FE
	HRSG G-10B	1.10	26.3	0.61	14.7	1.64	39.4	0.03	0.8	0.40	9.7	0.40	9.66	FE
	HRSG G-10C	1.10	26.3	0.61	14.7	1.64	39.4	0.03	0.8	0.40	9.7	0.40	9.66	FE
	HRSG G-10D	1.10	26.3	0.61	14.7	1.64	39.4	0.03	0.8	0.40	9.7	0.40	9.66	FE
	HRSG G-10E	1.10	26.3	0.61	14.7	1.64	39.4	0.03	0.8	0.40	9.7	0.40	9.66	FE
	SCR Burner	0.99	23.8	0.98	23.5	1.49	35.6	0.03	0.7	0.39	9.4	0.39	9.39	FE
Combustion - Flare														
Planned:	Pilot/Purge	0.09	2.2	0.16	3.8	0.49	11.7	0.00	0.0	0.03	0.6	0.03	0.63	FE
	Continuous	--	--	--	--	--	--	--	--	--	--	--	--	
	Infrequent	--	--	--	--	--	--	--	--	--	--	--	--	
	Oil Plant Shutdown	--	--	--	--	--	--	--	--	--	--	--	--	
Unplanned:	Infrequent - Sour	--	--	--	--	--	--	--	--	--	--	--	--	
	Infrequent	--	--	--	--	--	--	--	--	--	--	--	--	
Fugitive Components	Oil, valve, controlled	--	--	0.14	3.3	--	--	--	--	--	--	--	--	FE
	Oil, valve, UTM	--	--	0.02	0.5	--	--	--	--	--	--	--	--	FE
	Oil, connection, cont.	--	--	0.77	18.5	--	--	--	--	--	--	--	--	FE
	Oil, connection, UTM	--	--	0.09	2.1	--	--	--	--	--	--	--	--	FE
	Oil, Seal, dual	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Oil, PRV, controlled	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, valve, controlled	--	--	3.48	83.6	--	--	--	--	--	--	--	--	FE
	Gas, valve, UTM	--	--	0.40	9.6	--	--	--	--	--	--	--	--	FE

23-Jul-08

Table 5.2-3
Hourly and Daily Emissions
PTO No. 5704

Equipment Category	Emissions Unit	NOx lbs/hr	NOx lbs/day	ROC lbs/hr	ROC lbs/day	CO lbs/hr	CO lbs/day	SOx lbs/hr	SOx lbs/day	PM lbs/hr	PM lbs/day	PM10 lbs/hr	PM10 lbs/day	Federally Enforceable
Fugitive Components - cont	Gas, valve, NDE	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, Connection, Cont	--	--	1.12	26.9	--	--	--	--	--	--	--	--	FE
	Gas, Connection, UTM	--	--	0.10	2.4	--	--	--	--	--	--	--	--	FE
	Gas, Connection, NDE	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, seals, controlled	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, seals, dual	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, PRV, controlled	--	--	0.02	0.5	--	--	--	--	--	--	--	--	FE
	Gas, PRV, Unsafe	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, PRV to flare	--	--	0.00	0.0	--	--	--	--	--	--	--	--	FE
	Gas, PRV, tanks	--	--	0.06	1.4	--	--	--	--	--	--	--	--	FE
Crew Boats, Controlled	Main Eng, Cruise	2.92	5.8	0.52	1.0	0.88	1.8	0.25	0.5	0.30	0.6	0.30	0.59	FE
	Auxiliary Eng	2.17	4.3	0.17	0.3	0.47	0.9	0.13	0.3	0.15	0.3	0.15	0.30	FE
Tanks and Separators	Dry Oil Tank (T-1)	--	--	2.88	69.1	--	--	--	--	--	--	--	--	FE
	Reject Oil (T-2)	--	--	4.94	118.6	--	--	--	--	--	--	--	--	FE
	Wastewater (T-4)	--	--	0.03	0.8	--	--	--	--	--	--	--	--	FE
	Wastewater (T-8)	--	--	0.00	0.1	--	--	--	--	--	--	--	--	FE
	Wastewater (T-25)	--	--	0.02	0.6	--	--	--	--	--	--	--	--	FE
Combustion - Engines	Turbine Starter G-10A	6.05	6.05	0.49	0.49	1.30	1.30	0.07	0.07	0.43	0.43	0.43	0.43	FE
	Turbine Starter G-10B	6.05	6.05	0.49	0.49	1.30	1.30	0.07	0.07	0.43	0.43	0.43	0.43	FE
	Turbine Starter G-10C	6.05	6.05	0.49	0.49	1.30	1.30	0.07	0.07	0.43	0.43	0.43	0.43	FE
	Turbine Starter G-10D	6.05	6.05	0.49	0.49	1.30	1.30	0.07	0.07	0.43	0.43	0.43	0.43	FE
	Turbine Starter G-10E	6.05	6.05	0.49	0.49	1.30	1.30	0.07	0.07	0.43	0.43	0.43	0.43	FE
Solvent Usage	Cleaning/degreasing	--	--	1.34	10.7	--	--	--	--	--	--	--	--	

Table 5.2-4
Quarterly and Annual Emissions
PTO No. 5704

		NOx		ROC		CO		SOx		PM		PM10		Federally
Equipment Category	**Emissions Unit**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**Enforceable**
Combustion - Turbines	Turbine G-10A	1.53	6.13	0.44	1.75	4.93	19.71	0.08	0.33	0.60	2.41	0.60	2.41	FE
	Turbine G-10B	1.53	6.13	0.44	1.75	4.93	19.71	0.08	0.33	0.60	2.41	0.60	2.41	FE
	Turbine G-10C	1.53	6.13	0.44	1.75	4.93	19.71	0.08	0.33	0.60	2.41	0.60	2.41	FE
	Turbine G-10D	1.53	6.13	0.44	1.75	4.93	19.71	0.08	0.33	0.60	2.41	0.60	2.41	FE
	Turbine G-10E	1.53	6.13	0.44	1.75	4.93	19.71	0.08	0.33	0.60	2.41	0.60	2.41	FE
	Diverter Valve Leakage	0.35	1.40	--	--	--	--	--	--	--	--	--	--	FE
Combustion - External	HRSG G-10A	1.20	4.80	0.67	2.69	1.80	7.20	0.04	0.15	0.44	1.76	0.44	1.76	FE
	HRSG G-10B	1.20	4.80	0.67	2.69	1.80	7.20	0.04	0.15	0.44	1.76	0.44	1.76	FE
	HRSG G-10C	1.20	4.80	0.67	2.69	1.80	7.20	0.04	0.15	0.44	1.76	0.44	1.76	FE
	HRSG G-10D	1.20	4.80	0.67	2.69	1.80	7.20	0.04	0.15	0.44	1.76	0.44	1.76	FE
	HRSG G-10E	1.20	4.80	0.67	2.69	1.80	7.20	0.04	0.15	0.44	1.76	0.44	1.76	FE
	SCR Burner	1.08	4.34	1.07	4.29	1.63	6.50	0.03	0.13	0.43	1.71	0.43	1.71	FE
Combustion - Flare														
Planned:	Pilot/Purge	0.10	0.39	0.17	0.70	0.53	2.14	0.00	0.01	0.03	0.12	0.03	0.12	FE
	Continuous	0.09	0.37	0.17	0.66	0.51	2.04	0.05	0.18	0.00	0.11	0.00	0.11	FE
	Infrequent	0.05	0.20	0.09	0.36	0.28	1.11	0.03	0.10	0.02	0.06	0.02	0.06	FE
	Oil Plant Shutdown	0.01	0.03	0.01	0.05	0.04	0.15	0.00	0.01	0.00	0.01	0.00	0.01	FE
														FE
Unplanned:	Infrequent - Sour	0.04	0.16	0.07	0.29	0.22	0.89	0.43	1.71	0.01	0.05	0.01	0.05	FE
	Infrequent	0.26	1.02	0.45	1.81	1.39	5.55	0.13	0.50	0.08	0.30	0.08	0.30	FE
Fugitive Components	Oil, valve, controlled	--	--	0.15	0.61	--	--	--	--	--	--	--	--	FE
	Oil, valve, UTM	--	--	0.02	0.10	--	--	--	--	--	--	--	--	FE
	Oil, connection, cont.	--	--	0.85	3.38	--	--	--	--	--	--	--	--	FE
	Oil, connection, UTM	--	--	0.10	0.38	--	--	--	--	--	--	--	--	FE
	Oil, Seal, dual	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Oil, PRV, controlled	--	--	0.00	0.01	--	--	--	--	--	--	--	--	FE
	Gas, valve, controlled	--	--	3.81	15.25	--	--	--	--	--	--	--	--	FE
	Gas, valve, UTM	--	--	0.44	1.75	--	--	--	--	--	--	--	--	FE

Table 5.2-4
Quarterly and Annual Emissions
PTO No. 5704

Equipment Category	Emissions Unit	NOx		ROC		CO		SOx		PM		PM10		Federally Enforceable
		TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	
Fugitive Components - cont	Gas, valve, NDE	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, Connection, Cont.	--	--	1.23	4.91	--	--	--	--	--	--	--	--	FE
	Gas, Connection, UTM	--	--	0.11	0.44	--	--	--	--	--	--	--	--	FE
	Gas, Connection, NDE	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, seals, controlled	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, seals, dual	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, PRV, controlled	--	--	0.02	0.10	--	--	--	--	--	--	--	--	FE
	Gas, PRV, Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, PRV to flare	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Gas, PRV, tanks	--	--	0.06	0.26	--	--	--	--	--	--	--	--	FE
Crew Boats, Controlled	Main Eng, Cruise	0.01	0.02	0.00	0.00	0.00	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Auxiliary Eng	0.00	0.02	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	FE
Tanks and Separators	Dry Oil Tank (T-1) (Emerg	--	--	0.32	1.26	--	--	--	--	--	--	--	--	FE
	Reject Oil (T-2)	--	--	0.54	2.16	--	--	--	--	--	--	--	--	FE
	Wastewater (T-4)	--	--	0.00	0.01	--	--	--	--	--	--	--	--	FE
	Wastewater (T-8)	--	--	0.00	0.00	--	--	--	--	--	--	--	--	FE
	Wastewater (T-25)	--	--	0.00	0.01	--	--	--	--	--	--	--	--	FE
Combustion - Engines	Turbine Starter G-10A	0.03	0.03	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Turbine Starter G-10B	0.03	0.03	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Turbine Starter G-10C	0.03	0.03	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Turbine Starter G-10D	0.03	0.03	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
	Turbine Starter G-10E	0.03	0.03	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	FE
Solvent Usage	Cleaning/degreasing	--	--	0.49	1.95	--	--	--	--	--	--	--	--	

Table 5.3
Total Permitted Facility Emissions
PTO No. 5704

A. Peak Hourly (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burner	19.81	4.40	20.88	0.33	3.70	3.70
Flare	0.09	0.16	0.49	0.00	0.03	0.03
Fugitive Components	--	6.21	--	--	--	--
Crew Boats	5.09	0.62	1.35	0.39	0.45	0.45
Tanks and Separators	--	7.88	--	--	--	--
Solvent Usage	--	1.34	--	--	--	--
TOTALS (lb/hr)	**24.99**	**20.60**	**22.72**	**0.72**	**4.17**	**4.17**

B. Peak Daily (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burner	196.96	82.76	441.13	4.63	69.16	69.16
Flare	2.15	3.81	11.72	0.02	0.63	0.63
Fugitive Components	--	148.95	--	--	--	--
Crew Boats	10.18	1.38	2.70	0.77	0.90	0.90
Tanks and Separators	--	189.10	--	--	--	--
Solvent Usage	--	10.68	--	--	--	--
TOTALS (lb/day)	**209.29**	**436.69**	**455.55**	**5.42**	**70.69**	**70.69**

C. Peak Quarterly (Tons/Qtr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burner	8.49	3.74	20.02	0.21	3.12	3.12
Flare	0.55	0.97	2.97	0.63	0.13	0.13
Fugitive Components	--	6.80	--			
Crew Boats	0.01	0.00	0.00	0.00	0.00	0.00
Tanks and Separators	--	0.86	--	--	--	--
Solvent Usage	--	0.49	--	--	--	--
TOTALS (ton/qtr)	**9.05**	**12.85**	**22.99**	**0.83**	**3.25**	**3.25**

D. Peak Annual (Ton/yr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burner	33.79	14.92	80.03	0.82	12.47	12.47
Flare	2.18	3.86	11.87	2.51	0.64	0.64
Fugitive Components	--	27.18	--	--	--	--
Crew Boats	0.04	0.01	0.01	0.00	0.00	0.00
Tanks and Separators	--	3.45	--	--	--	--
Solvent Usage	--	1.95	--	--	--	--
TOTALS (ton/yr)	**36.01**	**51.37**	**91.91**	**3.33**	**13.11**	**13.11**

Table 5.4
Federal Potential to Emit
PTO No. 5704

A. Peak Hourly (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burn	19.81	4.40	20.88	0.46	3.70	3.70
Flare	0.09	0.16	0.49	0.00	0.03	0.03
Crew Boats	5.09	0.62	1.35	0.39	0.45	0.45
Tanks and Separators	--	7.88	--	--	--	--
Solvent Usage	--	1.34	--	--	--	--
Exempt	--		--	--	--	--
TOTALS (lb/hr)	**24.99**	**14.39**	**22.72**	**0.85**	**4.17**	**4.17**

B. Peak Daily (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burn	196.96	82.76	441.13	7.84	69.16	69.16
Flare	2.15	3.81	11.72	0.05	0.63	0.63
Crew Boats	10.18	1.38	2.70	0.77	0.90	0.90
Tanks and Separators	--	189.10	--	--	--	--
Solvent Usage	--	10.68	--	--	--	--
Exempt	--	--	--	--	--	--
TOTALS (lb/day)	**209.29**	**287.74**	**455.55**	**8.66**	**70.69**	**70.69**

C. Peak Quarterly (Tons/Qtr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burn	8.49	3.73	20.01	0.35	3.12	3.12
Flare	0.55	0.97	2.97	0.63	0.13	0.13
Crew Boats	0.01	0.00	0.00	0.00	0.00	0.00
Tanks and Separators	--	0.86	--	--	--	--
Solvent Usage	--	0.49	--	--	--	--
Exempt	3.72	0.41	2.20	0.18	0.26	0.25
TOTALS (ton/qtr)	**12.77**	**6.46**	**25.19**	**1.16**	**3.51**	**3.50**

D. Peak Annual (Ton/yr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Turbines/Boilers/SCR Burn	33.79	14.93	80.04	1.40	12.47	12.47
Flare	2.18	3.86	11.87	2.52	0.64	0.64
Crew Boats	0.04	0.01	0.01	0.00	0.00	0.00
Tanks and Separators	--	3.45	--	--	--	--
Solvent Usage	--	1.95	--	--	--	--
Exempt	14.88	1.63	8.78	0.71	1.05	1.00
TOTALS (ton/yr)	**50.89**	**25.82**	**100.70**	**4.63**	**14.16**	**14.11**

6.0 Air Quality Impact Analyses[6]

6.1 Compliance with Ambient Air Quality Standards

Impacts from operation of the GOHF, as originally proposed by Chevron, and the associated pipelines were modeled for NO_2, SO_2, CO and PM using the Complex II Model following the procedures specified in the APCD's *Authority to Construct Permit Processing Manual.* The ISC Model was used to predict ROC pollutant impacts. Based on the maximum-hour scenario, an ISC model was used to simulate the maximum ambient. ISC was found by the APCD to produce comparable results to those generated by Complex II with significant lower computer time requirements.

The following pollutants were analyzed for both phases:

- Nitrogen Oxides (NO_x)[7]
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x)[8]
- Particulate Matter (PM)[9]

Pre-construction monitoring data principally from the Gaviota station were used to provide the meteorological and background pollutant value input to the models.

A review was conducted to determine if any permitted emission sources, not accounted for in the pre-construction monitoring data, would be present during the installation or operation of the proposed project. The installation and operation of Exxon's Harmony, Heritage and Heather platforms, offshore of the Gaviota area were identified as having the potential to impact the same locations as the proposed project and were therefore included in the analysis.

In order to determine compliance with ambient air quality standards during the installation and operation of offshore platforms, the modeling results contained within the project EIR/EIS were used. For project modifications, the analysis of ATC 5704 was reviewed to determine if the modifications would jeopardize ambient air quality standards.

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6 This section provides an historical analysis that does not necessarily reflect current operations.
7 Calculated and reported as nitrogen dioxide (NO_2)

8 Calculated and reported as sulfur dioxide (SO_2)

9 Calculated and reported as all particulate matter smaller than 100 μm

The data and information provided in this section is based on the Point Arguello project as it was originally designed, installed and operated.

6.1.1 *Production Impact from Onshore Facilities*

Production emissions were modeled as 12 point sources and 35 ROC area sources occurring inside the facility boundary. Emission rates and stack parameters for each of these sources are given in Table 10.1-2 of ATC 5704 (issued 2/6/86). An array of 99 receptors was used for modeling of all pollutants except ROC, which had an array of 115 receptors.

The modeling results for the project are shown in Table 6.1. The project contribution of PM_{10} will be added to the existing background levels which exceeded the standards. This resulted in implementation of PM_{10} mitigation procedures outlined in the PM_{10} Emissions Reduction Study. No other violations of the ambient air quality standards were projected for normal operations of the Phase I oil and gas facilities.

Compliance with the SO_2 and NO_2 hourly standards was achieved only after Chevron relocated one of the Phase I tail gas scrubber stacks and agreed to remove the Phase II gas plant from the permit process.

The APCD investigated the potential for improving the permitability of Phase II gas plant by using grid power rather than power from cogeneration plant. In that the cogeneration plant did not contribute to peak SO_2 impacts, replacement of the cogeneration plant with grid power did not improve the permitability of the Phase II gas plant. As previously noted, the entire gas plant has since been de-permitted.

6.1.2 *Drilling and Production Impacts from Platforms*

Table 6.2 contains air quality impact results (obtained from the Project EIR/EIS) for normal operation of the three platforms and the five area study platforms. The total values include background values measured during the pre-construction monitoring period at Gaviota.

No violations of standards were predicted during normal operation, except in the case of PM_{10} which has a background value higher than the 24-hour standard.

Failure of the onshore 30 MMSCFD amine unit was projected to exceed the state 1-hour standard. Failure of the 60 MMSCFD amine unit proposed as a part of the Phase II gas plant is projected to cause exceedances of the state 1-hour SO_2 standard. A sulfur plant failure was predicted to cause an exceedance of the 1-hour, 3-hour, and 24-hour SO_2 standards.

6.1.3 Flaring Impacts from Onshore Facilities

Table 6.3 contains the flaring event impacts expected from the onshore facilities. The expected frequency and duration of each of the flaring events and stack parameters for modeling are shown in Table 10.1-3 of ATC 5704 (issued 2/6/86). Continuous purge and pilot is a daily activity and is included in the analysis of normal production impacts from the onshore facilities.

Controlled oil plant and gas plant shutdown flaring was not projected to exceed any standards. The use of an emergency caustic scrubber, designed for the gas processing facility, resulted in the compliance with the SO_2 standard.

Failure of the onshore 30 MMSCFD amine unit was projected to exceed the state 1-hour standard. Failure of the 60 MMSCFD amine unit proposed as a part of the Phase II gas plant is projected to cause exceedances of the state 1-hour SO_2 standard. A sulfur plant failure was predicted to cause an exceedance of the 1-hour, 3-hour, and 24-hour SO_2 standards. As previously noted, the entire gas plant has since been de-permitted.

6.1.4 Flaring Impacts from Platforms

Flaring impacts from the platforms were analyzed in the project EIR/EIS. Descriptive information on flaring events were shown in Table 10.1-3 of ATC 5704 (issued 2/6/86).

The modeling results, shown in Table 6.3, projected a peak 1-hour SO_2 concentration of 627, which approaches but did not exceed the state standard of 655 $\mu g/m^3$. The 1-hour NO_2 and 3-hour SO_2 standards were not predicted to be violated. The California 24-hour SO_2 standard is 131 $\mu g/m^3$, when simultaneous TSP and/or O_3 concentrations exceed 100 $\mu g/m^3$ and 10 pphm, respectively. The 24-hour TSP concentration did not predict an exceedance of 100 $\mu g/m^3$ and simultaneous occurrence of high ozone (above 10 pphm) and the flaring event is not likely; therefore, the state $SO_2/TSP/O_3$ standard is not anticipated to be exceeded during offshore flaring.

6.1.5 Project Contribution to Ozone Formation

The potential for the project to contribute to the formation of ozone was examined in the project EIR/EIS. A photochemical pollutant analysis was conducted using the Trace Model for a wide range of initial pollutant concentrations and trajectory paths. A detailed description of the analysis is contained in the EIR/EIS.

Table 6.4 summarizes the results of the ozone analysis. Significant increases in ozone levels were predicted from the project. Ozone levels in excess of the state standard (10.0 pphm) were predicted for facility operation and impacts above the federal standard (12.0 pphm) were predicted for upset conditions on the platforms and for facility operations under reduced wind speed conditions.

Mitigation of potential ozone standard violations are discussed in Section 7.0 (Offsets and Clean Air Plan Consistency.

6.2 Air Quality Increment Analysis

An increment consumption analysis was performed for the pollutants NO_2, TSP, PM_{10}, CO, SO_2 and ROC. An examination was first conducted to identify any existing sources which would consume increment within the general vicinity of the project site. Increment consuming sources include major stationary sources (per 40 CFR 52.21) constructed since January 6, 1975, and all sources constructed, modified or otherwise permitted to increase emissions after either August 8, 1978 (for TSP and SO_2) or January 1, 1984 (for PM_{10}, NO_2, CO and ROC). The only increment consumers identified in the project area, in addition to the proposed project, were Exxon's Platforms Harmony, Heritage and Heather, which were approved for installation by the US Minerals Management Service.

The same modeling methodology was used for increment analysis as was employed for the standards compliance analyses (see Section 6.1). For the computation of NO_2 by the ozone limiting method, the highest ozone value observed during pre-construction monitoring, a value of 14 pphm, was used. This value was measured at 1200 on April 14, 1984, at the County's El Capitan monitor. Neither PXP's Gaviota monitor or Shell's Molino monitor were operating during this peak ozone event for the pre-construction monitoring period.

The results of the increment analysis are shown in Table 6.5. During facility operation maximum increment consumption from the onshore oil and gas facility was anticipated to exceed the allowable maximum for only ROC (3-hour).

Increment consumption from platform operation was determined to be less than that shown for the oil and gas processing facility. Simultaneous emissions from Exxon's platforms were not projected to contribute to the maximum modeled increments.

During the first year of operation increment fees ($333.00 per year per microgram above lower increment level) required were $244.00 per day for NO_2, $3.00 per day for PM_{10} and $1874.00 per day for ROC. The required fee is reduced by 10% per year, as per APCD rules. The final increment fee payment was made in November 1998.

6.3 Vegetation and Soils Analysis

The land in the general area of the proposed project is used for grazing. At sufficient concentration and duration, ambient air pollutants, specifically ozone, sulfur dioxide, nitrogen dioxide, and various combinations of the three, can injure vegetation.

An ozone concentration of 0.25 ppm over a six hour period has been shown to injure plants. Additional studies have also demonstrated slight injury to sensitive plants at ozone exposure levels of 0.02-0.03 ppm for an 8-hour duration and 0.08-0.15 ppm for 2 hours. Evidence of minimal foliar injury to trees and shrubs at ozone concentrations of 0.2-0.5 ppm for 1 hour and to agricultural crops at 0.2-0.41 ppm for one-half hour has also been substantiated.

The maximum hourly ozone concentration expected during construction and production of the proposed project was projected to be 0.12 ppm (0.13 ppm in rare occasions). Based on past studies this concentration may cause slight damage to sensitive plants.

Recent studies of sulfur dioxide exposure show injury thresholds at 0.3 ppm for 8 hours (for middle-aged plants), at 0.14 ppm for 15-20 hours (for oat seedlings), and at an 0.007-0.010 ppm average for the growing season. The maximum hourly ambient concentration of sulfur dioxide expected during operation of the facility is approximately 0.25 ppm, (assuming implementation of the mitigation measures in section 6.1) which is below the thresholds cited by these studies. Therefore, no plant injury is expected from sulfur dioxide.

Nitrogen dioxide sensitivity has been cited in the literature at concentrations of 2.5 ppm for a 4-hour duration for tomato seedlings and other plants with middle-aged leaves. Leaf symptoms have been observed at 1.6-2.6 ppm for 2 day exposures and 20 ppm for 1-hour exposures. The maximum hourly ambient concentration of nitrogen dioxide predicted during the production phase would be 0.23 ppm, which is well below the injury threshold cited. Therefore, no plant injury is expected from nitrogen dioxide emissions.

During the production phase, total emissions from the facility were predicted to be 245 pounds per day of sulfur dioxide and 950 pounds per day of nitrogen oxides. Annual deposition of sulfates and nitrates onto the surrounding soils will be minimal, based on the large project area over which the pollutants are dispersed. In addition, the pronounced alkalinity of the soils will ameliorate the effects of the minor decrease in pH expected from nitrate or sulfate deposition. No long term buildup of deposition products is expected because of utilization of these compounds by existing vegetation. In addition, the facility was not anticipated to emit heavy metals or other toxic substances which could damage soils used for crop or forage production. Therefore, no impact on soils was predicted to occur from project emissions.

6.4 Potential to Impact Visibility and Opacity

During facility operations the potential exists for opacity violations due to flaring activities and due to operation of the diesel-fired internal combustion engines. The potential for these violations are minimized through the use of a smokeless flare and through proper operation and maintenance of the IC engines.

6.5 Health Risk Assessment

The GOHF is not of significant risk status (significant risk is >10 in one million for cancer risk and HI=1.0 for acute and chronic non-cancer risk). As a result, an Update Summary Form is required to be submitted by this facility each four years. The last Update Summary Form was submitted in 1998 (based on 1997 operations). The next Update Summary Form is due in the Spring 2002 (for 2001 operations).

6.6 Public Nuisance

Historically, oil and gas processing facilities handling high sulfur content petroleum within the County of Santa Barbara have been the subject of numerous public complaints regarding odors and other related public nuisance factors. Based on these experiences it was considered particularly important to evaluate the potential for public nuisance from the proposed facilities. Emissions from the operation phases of the project were reviewed to determine compliance with APCD Rules 205.A and 303, which relate to the prevention of public nuisance as required by Section 41700 of the State Health and Safety Code.

As initially designed and operated, there was a comparatively greater potential for public nuisance due to emissions of reduced sulfur compounds which could occur during facility operation than there is under the current permit for this facility. In the original design and operation of GOHF both the high sulfur content of the petroleum feedstock and the ethyl mercaptan addition unit used to odorize the natural gas, propane and butane were potential sources of reduced sulfur compounds. Additional sources of reduced sulfur emissions included the amine unit, the sulfur unit, the tail gas unit, the sour gas pipeline and fugitive emissions from gas and oil handling facilities.

As such, it was determined that piping for the sour gas facility would contain process streams with H_2S content above the 825 ppm level specified in Ordinance No. 2832 as the trigger point for classifying the operations to be in "Potentially Hazardous Emission Area". Petroleum operations in Potentially Hazardous Emission Areas are required to submit a plan for detecting and monitoring emissions and must conduct operations so that ambient H_2S concentrations do not exceed the values set forth in Ordinance No. 2832 for the protection of public health. However, substantially lower reduced sulfur concentrations than those specified in the Ordinance have the potential to cause a public nuisance. Ordinance 2832 is also triggered by petroleum facilities "in the vicinity of any residence or place of public gathering which could affect the safety or well being of others". Places of public gathering in the vicinity of PXP facilities include highway travelers immediately to the south and beach users to the southwest and southeast.

Since the human odor threshold for H_2S is 0.00047 ppm (Ref. SCAQMD EIR Handbook, App. M), it was determined that odors will, at times, likely be detectable outside the property line. Thus, due to the potential for odorous emissions from the facilities, an odor monitoring program was required. This program required several odor monitoring stations, including the Gaviota East and Gaviota West Odor stations. Odor monitoring was also required by the County Final Development Plan (condition E-4). GOHF no longer receives sour gas from the platforms. The Gaviota East and West odor stations were subsequently decommissioned following the installation of three H_2S monitoring sensors under ATC 10332.

6.7 Ambient Air Quality Monitoring

In order to comply with the pre-construction monitoring requirements of APCD Rule 205.C.3.b.5, PXP installed an ambient air quality monitor in July, 1984 at their Gaviota site. The monitoring station was capable of measuring NO, NO_x, SO_2, ROC, THC, TSP, PM_{10}, ozone and meteorological parameters. This pre-construction monitoring data was used in the Air Quality Impact Analysis discussed in ATC 5704 (issued 2/6/86) and summarized in that permit. Locations outside the facility boundary were identified for the citing of ambient air quality monitors during and after construction activities. As required under the County Preliminary Development Plan Condition E-4, PXP installed monitoring stations at Jalama Beach, Point Conception, Gaviota and Carpinteria to provide data on the impacts from platform and facility construction and operation and regional ozone levels. The Jalama Beach and Point Conception monitoring stations were decommissioned by the APCD on December 1, 1995 and April 06, 1998, respectively, after a review of the data determined that these stations had addressed their objectives and satisfied the operational monitoring criteria.

Two monitor locations were identified in the vicinity of the GOHF. One location is north of the facility (UTM 3818.48 N and 756.66 E) and 390 feet elevation. The second site is north-west of the facility (UTM 3818.49 N and 756.16 E) at 400 feet elevation. These stations were decommissioned on April 11, 1998 after a review of the data determined that these stations had addressed their objectives and satisfied the operational monitoring criteria.

Table 6.6 summarizes the remaining operational station site and parameters to be monitored. If deemed necessary by the APCD, additional monitoring stations shall be installed by PXP to monitor operational impacts or upset/breakdown impacts.

6.8 Emergency Episode Plans and Curtailment Plans for the Protection of Ambient Air Quality Standards

Pursuant to APCD Rule 603.A.1, PXP is required to maintain an Emergency Episode Plan, approved by the APCD, for this facility. The contents of the Emergency Episode Plan must comply with the provisions specified in Rule 603.A.2. The Episode Plan was approved on April 20, 1988 and most recently updated on February 5, 2005. The update adequately addressed the staff contact changes. In addition, the County Development Plan Condition E-3 and E-5 originally required PXP to submit for APCD approval of an "Air Pollution Curtailment Plan" to provide for the protection of ambient air quality standards during construction and operation of the facility. However, during a Condition

Effectiveness Study (dated November 22, 1991) of the Final Development Plan, the requirement for curtailment of operation activities was deleted, since curtailment of plant operations would result in increased flaring activities, thus having a greater adverse impact than continued operations.

Table 6.1
PXP GOHF- PTO 5704
Air Quality Impacts
Onshore Facilities - Production Phase [10]

POLLUTANT	AVERAGING TIME (μg/m³)	PROJECT CONTRIBUTION (μg/m³)	BACKGROUND (μg/m³)	TOTAL (μg/m³)	STANDARD (μg/m³)
NO_2	1-Hour	348	75	423	470
	Annual	9	19	28	100
TSP [11]	24-Hour	16	124	140	260
	Annual	2	23	25	75
PM_{10}	24-Hour	15 [12]	58	73 [13]	50
	Annual	2	15		30
CO	1-Hour	964	8,000	8,964	23,000
	8-Hour	205	2,663	2,868	10,000
SO_2	1-Hour	590	47	637	655
	3-Hour	199	35	234	1,300
	24-Hour	31	10	41	131
	Annual	3	0	3	80
ROC	3-Hour	2,095	318	2,413	160 [14]

9. This was Table 6-2 in ATC 5704 (2/6/86).
10. TSP standard no longer applicable. TSP increment is still applicable for both 24-hour Class II increment (37μg/m³) and the annual Class II increment (19 (μg/m3).
12. PM10 emissions are assumed to be 96 percent of TSP emission rate.
13. Project contribution of PM10 adds to existing standard violations.
14. ROC standard is retained by the APCD for ROC increment tracking as a precursor to ozone formation.

Table 6.2
PXP GOHF- PTO 5704
Air Quality Impacts
Platforms - Production Phase [15]

POLLUTANT	AVERAGING TIME ($\mu g/m^3$)	PROJECT CONTRIBUTION ($\mu g/m^3$)	BACKGROUND ($\mu g/m^3$)	TOTAL ($\mu g/m^3$)	STANDARD ($\mu g/m^3$)
NO_2	1-Hour	259	75	334	470
	Annual	26	19	45	100
TSP	24-Hour	15	124	139	n/a
	Annual	1.5	23	25	n/a
PM_{10}	24-Hour	15	58	73 [16]	50
	Annual	1.5	15	16.5	30
CO	1-Hour	91	8,000	8,091	23,000
	8-Hour	64	2,663	2,727	10,000
SO_2	1-Hour	19	47	66	655
	3-Hour	17	35	52	1,300
	24-Hour	8	10	18	131
	Annual	1.9	0	1.93	80

15. This was Table 6-4 in ATC 5704-06 (1/30/92) and ATC 5704 (2/6/86).
16. Project contribution of PM10 adds to existing standard violations.

Table 6.3
PXP GOHF - PTO 5704
Flaring Impacts- Production Phase [17]

FLARING EVENT [18]	1-HOUR NO_2 IMPACT ($\mu g/m^3$)	1-HOUR SO_2 IMPACT ($\mu g/m^3$)	3-HOUR SO_2 IMPACT ($\mu g/m^3$)	24-HOUR SO_2 IMPACT ($\mu g/m^3$)
ONSHORE				
- Continuous purge and pilot [19]	--	--	--	--
- Intermittent Pigging [c]	--	--	--	--
- Controlled oil plant shutdown	328	--	--	--
- Controlled gas plant shutdown [20]	357 [22]	304	185	29
- Amine Failure				
(30 MMSCFD)	186 [f]	1,576	545	74
(60 MMSCFD) [21]	216 [f]	1,997	685	91
- Sulfur plant failure [d]	352 [f]	8,644	2,901	368
OFFSHORE				
- Platforms	271	627	460	248
STANDARDS	470 (State)	655 (State)	1,300 (Federal Secondary)	131 (State) 365 (Federal Primary)

17. This was Table 6-5 in ATC 5704 (2/6/86).
18. Values are totals including facility contribution and background values from Table 10.1-3 of ATC 5704 (2/6/86).
19. Contributions are included in normal operation of onshore facility.
20. These emission scenarios are based on of 90 percent SO_2 reduction by use of the emergency amine scrubber.
21. 60 MMSCFD amine unit failure would be associated with Phase II gas plant.
22. NO_2 value scaled from SO_2 value.

Table 6.4
PXP GOHF - PTO 5704
Onshore Ozone Impacts of Project Facilities [23]

Project Facilities	Peak Onshore Ozone Concentration (pphm)	Increase Over Baseline Concentration (pphm)
Trajectory 1 - Offshore Carpinteria to Project platforms to Santa Ynez Valley		
3 Platforms	11.2 (12.6) [24]	1.1 (2.5) [b]
8 Platforms	11.5	1.4
Trajectory 2 - Project platforms to offshore Gaviota to Goleta		
3 Platforms	10.8 (13.0) [25]	0.1 (2.3) [c]
8 Platforms	11.0	0.3
Trajectory 3 - Gaviota to offshore Gaviota to Goleta		
Onshore Processing Plant	10.3	0.0
Trajectory 4 - Project platforms to offshore Gaviota to Ojai		
3 Platforms	11.7 (15.1) [b]	0.6 (4.0) [b]
8 Platforms	11.3	0.2

23 This was Table 6-6 in ATC 5704 (2/6/86).
24 Facility upset conditions.
25 Reduced wind speed over platforms.

Table 6.5
PXP GOHF - PTO 5704
Maximum Project Increment Consumed [26, 27]

POLLUTANT	AVERAGING TIME	INCREMENT CONSUMPTION [28] ($\mu g/m^3$)	ALLOWABLE INCREMENT ($\mu g/m^3$)
NO_2	1-Hour	367	100-470 [29]
	Annual	9	25
TSP	24-Hour	16	37
	Annual	2	19
PM_{10}	24-Hour	15	12-50
CO	1-Hour	964	10,000
	8-Hour	205	2,500
SO_2	3-Hour	199	512
	24-Hour	31	91
	Annual	3	20
ROC	3-Hour	2,095 [30]	40-160 [d]

26 This was Table 6-6 in ATC 5704 (2/6/86).

27 The results are for equipment allowed under the permit. Preliminary modeling of the proposed project with both Phase I and Phase II gas plants predicted exceedances of the State 1-hour standards for NO2 and SO2.

28 Maximum increment consumed is due to operation of the oil and gas plant.

29 Increment fee is imposed for impact above lower limit.

30 ROC increment revised per APCD 6/2/89 letter.

Table 6.6
PXP Gaviota – PTO 5704
Monitoring Station Requirements

Monitoring Station	O_3	NO	NO_x	NO_2	SO_2	THC	H_2S	PM_{10}	ROC	TRS	Ave WS	Ave WD	VWS	ATM	SIGMA W	SIGMA V	SIGMA T	Int Stn Temp	Res WS	Res WD
Carpinteria	x	x	x	X							x	x		x			x	x	x	x

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 Clean Air Plan

Santa Barbara County has historically violated both the federal (0.12 ppm) and state (0.09 ppm) one-hour ambient air quality standards for ozone. The county also violates the new state (0.070 ppm) eight hour ambient ozone standard. Ambient air quality data collected since 1999 show that Santa Barbara County has attained the federal one-hour ozone standard. The APCD developed, adopted, and submitted the 2001 Clean Air Plan (2001 Plan) to USEPA to demonstrate that the County will maintain the federal standard through 2015 and officially requested that the County be re-designated to an attainment area for federal purposes. On July 9, 2003, USEPA published a final rule approving the 2001 Clean Air Plan and re-designating Santa Barbara County as an attainment area for the federal one-hour ozone standard. This action became effective on August 8, 2003. On December 16, 2004, the APCD adopted the 2004 Clean Air Plan providing a three year update to the 2001 Plan for state purposes only. Santa Barbara County was designated attainment for the federal 8-hour ozone standard (0.08 ppm) effective June 15, 2004.

7.2 Offset Requirements and ERCs

APCD rules and regulations require that emissions from the entire project, when considered in conjunction with emission reductions proposed by the applicant for existing sources, result in a Net Air Quality Benefit. Additionally, operational emissions must be consistent with the Clean Air Plan ("CAP") and must not interfere with reasonable further progress toward attainment and maintenance of ozone standards.

The agreement entitled "*Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Project Preliminary Development Plan No. 83-DP-32-CZ*", (signed August 19, 1985, and amended on September 8, 1992), hereinafter referred to as the "Arguello/APCD Contract" and the "*OCS Ozone Mitigation Agreement*" (signed September 8, 1992 and subsequent amended three times on September 5, 1995; October 22, 1996 and May 20, 1997).) provides specific procedures PXP must implement to ensure that project emissions, including operation emissions onshore, nearshore and on the OCS, are consistent with the CAP and result in a Net Air Quality Benefit and reasonable further progress provisions of the CAP. *OCS Ozone Mitigation Agreement* (approved September 8, 1992).

APCD rules require existing source emission reductions to be in place prior to the initiation of and for the duration of the project's emissions. The emission reductions must be quantifiable, surplus, permanent and enforceable. When permitted in 1986, PXP obtained emission reductions/offsets through the following mechanisms: a written agreement between the APCD and PXP, a modification of existing PXP permits and a written agreement between the owner of emission reduction sources and PXP with the APCD as third party beneficiary.

Offset credit is based on actual demonstrated emissions reductions for each offset source, adjusted for the distance factor between the offset and the project (the OCS emission offset ratio is specified in the *OCS Ozone Mitigation Agreement*). Source testing and further quantification of emissions, using procedures approved by the APCD, is necessary to ensure the actual emissions reductions from each source used as offsets occurs throughout the life of the Project.

7.3 Onshore Offset Requirements

Pursuant to APCD Regulation VIII, offsets have been determined necessary for facility operation emissions of NO_x and ROC. These emissions must be offset consistent with APCD and Federal rules and policies. Tables 7.1-1 and 7.1-2 detail the emission offsets required for the Project. Tables 7.2-1 and 7.2-2 provide specific details for each of the ERC sources.

Although the NEI totals are required to be offset and are reflected in Table 5.3, the ROC NEI total in Table 5.3 does not correspond to (i.e., they are greater than) the ROC "Net Emissions from Project" total listed in Table 7.1-2 (emissions required to be offset). This is due to the fact that a correction was made to the T-2 tank calculation. The tank "annual throughput - gal" variable, erroneously listed as 5.04E+07, was corrected to 5.04E+08. This resulted in a 1.2 tpy increase in ROC emissions, however, these do not constitute NEI.

7.4 Offshore Offset Requirements

The APCD/PXP Contract and the *OCS Ozone Mitigation Agreement* provided for mitigation of OCS emissions which impact onshore air quality. These contracts provide for reductions in OCS project emissions as well as the application of additional controls on non-project related onshore sources. In addition, the *OCS Ozone Agreement* requires that OCS project emissions be offset at a ratio of 1.0:1.0.

The OCS platform emission totals (potential-to-emit) are detailed in the permits for these platforms. However, the project is required to offset the "allowable emissions" from the platforms not the potential-to-emit totals. The "allowable emissions" are stipulated in the *OCS Ozone Mitigation Agreement* (subsequently revised by PTO 5704 Exhibit 1) and are summarized in Table 5.1 (II) of this permit.

Through the implementation of the procedures specified above, the APCD is able to make the finding that the project will result in a Net Air Quality Benefit and is consistent with the CAP, as necessary for the issuance of the ATC permit. Tables 7.1-1, 7.1-2, and 7.1-3 show the emission offsets required by the *OCS Ozone Mitigation Agreement*. Tables 7.2-1 and 7.2-2 provide the specific details for each of the ERC sources.

7.5 ERC Source Verification

With the exception of facilities that have shut down permanently, the APCD regularly inspects each of the emission offset sources for compliance with emission reduction requirements. For combustion sources, this may include an annual emissions source test to ensure that the control efficiencies are maintained.

Table 7.1-2
GOHF - PTO 5704
POINT ARGUELLO PROJECT
PROJECT OPERATION EMISSIONS AND OFFSETS

REACTIVE ORGANIC COMPOUNDS (ROC)

NEI EMISSIONS FROM PROJECT	TPQ	TPY
Phase I Oil and Gas Plants	12.54	50.17

OCS EMISSIONS FROM PROJECT	TPY
OCS Mitigation Agreement Emission Limit	153.66

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions TPQ	Emission Reductions TPY	Distance Factor	Offset Credit TPQ	Offset Credit TPY
Fugitive Hydrocarbon I&M Program/Shutdown at Phillips Tajiguas Gas Plant	5.68	22.72	1.2	4.73	18.93
Fugitive Hydrocarbon I&M Program at Venoco Ellwood Oil and Gas Plant	11.27	45.07	1.5	7.51	30.05
ERC Certificate 0135	0.210	0.839	1.5	0.140	0.559
ERC Certificate 0137	0.057	0.228	1.2	0.048	0.190
ERC Certificate 0018-0331[a]	0.16	0.65	1.5	0.11	0.43
ERC Certificate 0131-0909[b]	0.002	0.007	1.5	0.001	0.005
TOTAL[c]	**17.38**	**69.51**		**12.54**	**50.17**

EMISSION REDUCTION SOURCES (OCS)	TPY
Fugitive Hydrocarbon I&M Program/Shutdown at Phillips Tajiguas Gas Plant	74.09
Fugitive Hydrocarbon I&M Program at Venoco Ellwood Oil and Gas Plant	56.05
Fugitive Hydrocarbon I&M Program at Venoco Carpinteria Gas Plant	13.46
Fugitive Hydrocarbon I&M Program/Shutdown at Chevron Pt. Hope (CUSA)	5.25
Venoco Seep Containment Device	4.61
E-4, E-7, E-9 Contract 30-Year Credit	0.20
TOTAL	**153.66**

29-Feb-08

Notes:

a. Additional ERCs needed for flare emission increases. These are non-MERC. (See ATC/PTO 10137 project file for additional details).

b. This ERC certificate was provided by Arguello to cover the ROC ERC shortfall resulting from the Keoki engine change out which occurred in 2005.

c. The "Net Emissions from Project" ROC totals do not equal the Table 5.3 totals (which represent NEI) because the Table 5.3 totals include additional emissions from a correction to the T-1 tank calculation. An error in the throughput value for this tank was corrected and resulted in an additional 1.2 tpy ROC emissions. These emissions do not constitute actual NEI.

Table 7.1-1[a]
GAVIOTA PLANT - PTO 5704
POINT ARGUELLO PROJECT
PROJECT OPERATION EMISSIONS AND OFFSETS

OXIDES OF NITROGEN (NOx)

NEI EMISSIONS FROM PROJECT	TPQ	TPY[b]
Phase I Oil and Gas Plants	8.99	35.95

OCS EMISSIONS FROM PROJECT	TPY
OCS Mitigation Agreement Emission Limit	341.16

	Emission Reductions		Distance	Offset Credit	
EMISSION REDUCTION SOURCES (NEI)	TPQ	TPY	Factor	TPQ	TPY
Control/Shutdown Engines at Phillips Tajiguas Gas Plant	8.55	34.18	1.2	7.12	28.48
Utility Displacement Credit	1.80	7.20	1.0	1.80	7.20
ERC Certificate 0137		0.169	1.2		0.141
ROC ERC Certificate 0018-0331		0.18	1.5		0.12
TOTAL	**10.35**	**41.38**		**8.92**	**35.94**

EMISSION REDUCTION SOURCES (OCS)	TPY
Control/Shutdown Engines at Phillips Tajiguas Gas Plant	2.76
Control IR Compressor Engines at Venoco Carpinteria Gas Plant	10.53
Control Cooper Compressor Engines at Venoco Carpinteria Gas Plant	76.70
Control/Shutdown Cooper Compressor Engine at Chevron Pt. Hope (CUSA)	118.84
Control/Shutdown Cooper Compressor Engine at Chevron Pt. Hope (ARCO)	14.28
Control Engines at Southern California Gas Co. Dehydration Plant - More Mesa	96.06
E-4, E-7, E-9 Contract 30-Year Credit	22.00
TOTAL	**341.17**

29-Feb-08

Notes:

(a) As detailed below, the ROC offsets from ERC certificate No. 0018-0331 are sufficient to offset the ROC emissions liability (0.65 tpy) from the flare emission increase and leaves 0.35 tpy excess ROC emission offsets. The NOx emission liability is 0.39 tpy for which only 0.21 tpy of NOx offsets is available. This NOx ERC shortfall (0.18 tpy) is satisfied by the 0.35 tpy excess ROC ERCs which results in a 2.0:1.0 interpollutant trade ratio.

	NOx (tpy)	ROC (tpy)
ATC 10137 Emission Liability (see page 3 of permit)	0.26	0.43
NAR Offset Ratio @ 1.5:1 (offsets required))	0.39	0.65
Available ERCs - ERC Certificate (see page of 3 permit)	0.21	1.0
Shortfall/Excess	-0.18	0.35
NOx for ROC Ratio = 2.0:1.0		

Table 7.1-3
GAVIOTA OIL HEATING FACILITY - PTO 5704
POINT ARGUELLO PROJECT
PROJECT OPERATION EMISSIONS AND OFFSETS

REACTIVE ORGANIC COMPOUNDS (ROC)

NEI EMISSIONS FROM PROJECT	TPQ	TPY
ByPass Project	0.25	1.00

EMISSION REDUCTION SOURCES (NEI)		Emission Reductions TPQ	Emission Reductions TPY	Distance Factor	Offset Credit TPQ	Offset Credit TPY
ERC Certificate 0119-0909		0.25	1.00	1.50	0.17	0.68
ERC Certificate 0120-0909		0.11	0.44	1.50	0.07	0.28
ERC Certificate 0130-0909		0.015	0.06	1.50	0.01	0.04
	TOTAL	**0.38**	**1.50**		**0.25**	**1.00**

Table 7.2-1a
GOHF – PTO 5704
DESCRIPTION OF NEI NO_x EMISSION REDUCTION SOURCES

Equipment	Location	Control Technology	Date Control In Effect	Required Minimum Control Efficiency[a]	Minimum Required Emission Reductions[b] TPQ	TPY
White Superior I.C. Engines	Tajiguas Gas Plant	Plant Shutdown	Jan 1991	NO_x - 100 percent	8.55	34.18
Utility Displacement Credit	Gaviota Cogen Plant	Credit	Dec 1987	n/a	1.80	7.20
ERC Certificate #0016	SB Channel	Marine Eng Repower	Jan 1999	NOx – 4.5 g/bhp-hr	0.10	0.39
ERC Certificate #0018	SB Airport	SB Aerospace Shutdown	Mar 1999	IP Trade 2:1 ratio	(c)	(c)
TOTAL NO_x ERCs					**10.44**	**41.77**

Notes:
a. Minimum required control efficiency for catalytic converters is measured across the control device in as-found conditions.
b. This table shows ERC quantities applicable to NEI liability only. Additional NO_x ERCs created through the control of the Tajiguas I.C. engines, in the amounts specified in this permit, are designated as ERCs for the OCS.
c. Values included in ERC Certificate #0016 line item.

Table 7.2-1b
GOHF – PTO 5704
DESCRIPTION OF OCS NO_x EMISSION REDUCTION SOURCES

Equipment	Location	Control Technology	Date Control In Effect	Required Minimum Control Efficiency[a]	Minimum Required Emission Reductions[b] TPQ	TPY
E-4-7-9 Contract 30 Year Credit	n/a	n/a	n/a	n/a	5.50	22.00
Cooper I.C. Engine (CUSA)	Platform Hope	Shutdown	Jan 1986	n/a	29.71	118.84
White Superior I.C. Engines	Tajiguas Gas Plant	Plant Shutdown	Jan 1991	NO_x - 100 percent	0.49	1.97
Ingersoll-Rand IC Engine #1 (CUSA)	Carpinteria Gas Plant	Pre-Stratified Charge	Oct 1986	NO_x - 399 lb/MMscf	2.63	10.53
Ingersoll-Rand IC Engine #3 (CUSA)	Carpinteria Gas Plant	Pre-Stratified Charge	Oct 1986	NO_x - 790 lb/MMscf	(c)	(c)
Cooper I.C. Engine (CUSA)	Carpinteria Gas Plant	Clean Burn	Feb 1986	NO_x - 185 lb/MMscf	19.18	76.70
Cooper I.C. Engine (ARCO)	Platform Hope	Shutdown	Jan 1986	n/a	3.57	14.28
Ingersoll-Rand IC Engines	SOCAL Gas - More Mesa	Catalytic Converter	Jan 1986	NO_x - 80 percent	23.96	96.06
TOTAL OCS NO_x ERCs					**85.29**	**341.17**

Notes:

a. Minimum required control efficiency for catalytic converters is measured across the control device in as-found conditions. The minimum control efficiency for Chevron USA's Cooper-Bessemer and Ingersoll-Rand engines are shown as the required minimum controlled emission factor corrected to historical loads (in units of lb NO_x/MMSCF).

b. This table shows ERC quantities which are designated as OCS ERCs. Additional ERCs created through the control of the Tajiguas I.C. engines, in the amounts specified in this permit, are designated to mitigate NEI emissions liability.

c. The total ERC's from both IR engines #1 and #3 dedicated to the project is 10.53 tpy.

Table 7.2-2a
GOHF – PTO 5704
DESCRIPTION OF NEI ROC EMISSION REDUCTION SOURCES

Equipment	Location	Control Technology[a]	Date Control In Effect	Required Minimum Control Efficiency	Minimum Required Emission Reductions[b] TPQ	TPY
Fugitive ROC Components	Tajiguas Gas Plant	Equipment Shutdown	Jan 1991	ROC - 100 percent	5.68	22.72
Fugitive ROC Components	Ellwood Gas Plant	I&M Program	Jun 1989	ROC - 69 to 79 %	11.27	45.07
Marine Vessel Repowering Program	Santa Barbara Channel	Marine Eng Repowers	Oct 1996	ROC - 0.58 g/bhp-hr	0.41	1.65
ERC Certificate #0018	SB Airport	SB Aerospace Shutdown	Mar 1999	IP Trade 2:1 ratio	0.16	0.65
ERC Certificate #0045-1205	F/V Chameleon	Lo-NOx Diesel ICE	Dec 2000	ROC - 0.58 g/bhp-hr	0.01	0.028
TOTAL NEI ROC ERCs					**17.53**	**70.11**

Notes:

a. Consistent with District-approved I&M programs and methods. Control efficiencies for I&M programs are source specific. Please reference the District's Administrative files for source/component specific control requirements.

b. This table shows ERC quantities applicable to NEI liability only. Additional ROC ERCs created through the control of the Ellwood and Tajiguas fugitive ROC components, in the amounts specified in this permit, are designated as OCS ERCs.

c. A contingency factor of 1.35 was applied to the Marine Vessel Repowering Program.

Table 7.2-2b
GOHF – PTO 5704
DESCRIPTION OF OCS ROC EMISSION REDUCTION SOURCES

Equipment	Location	Control Technology[a]	Date Control In Effect	Required Minimum Control Efficiency	Minimum Required Emission Reductions[b] TPQ	TPY
E-4-7-9 Contract 30 Year Credit	n/a	n/a	n/a	n/a	0.05	0.20
Fugitive ROC Components	Tajiguas Gas Plant	Equipment Shutdown	Jan 1991	ROC - 100 percent	18.52	74.09
Fugitive ROC Components	Ellwood Gas Plant	I&M Program	Jun 1989	ROC - 69 to 79 %	14.01	56.05
Fugitive ROC Components (CUSA)	Carpinteria Gas Plant	I&M Program	Apr 1986	ROC - 79 percent	3.37	13.46
Fugitive ROC Components (CUSA)	Platform Hope	Shutdown	Apr 1986	n/a	1.31	5.25
Seep Containment Device (ARCO)	Coal Oil Point	Containment Structure	Mar 1991	n/a	1.15	4.61
TOTAL OCS ROC ERCs					**38.42**	**153.66**

Notes:
a. Consistent with District-approved I&M programs and methods. Control efficiencies for I&M programs are source specific. Please reference the District's Administrative files for source/component specific control requirements.
b. This table shows ERC quantities which are designated as OCS ERCs. Additional ROC ERCs created through the control of the Ellwood and Tajiguas fugitive ROC components, in the amounts specified in this permit, are designated to mitigate NEI emissions liability.

8.0 Lead Agency Permit Consistency

8.1 CEQA Requirements for PTO 5704

Pursuant to the *Environmental Review Guidelines for the Santa Barbara County Air Pollution Control District* (October 1995), the issuance of this Permit to Operate is exempt from CEQA review. The PTO relies on and is consistent with ATC 5704 (including all updates). No discretion or judgment is required in the granting of this permit.

8.2 Summary of CEQA Findings for ATC 5704 (Original Project)

The California Environmental Quality Act ("CEQA") requires that both "lead" and "responsible" agencies make certain findings in approving projects. The Santa Barbara County Resource Management Department, the CEQA lead agency for the original approval of this project, has made the necessary findings for project approval. These findings include consideration of environmental documents, Class I and II impacts, project alternatives, benefits of the project and statements of overriding consideration. On December 21, 1984, the Santa Barbara County Planning Commission approved the project and the CEQA findings.

The complete CEQA analysis is presented in the project EIR and ATC 5704 and subsequent permit modifications. A summary of these findings is as follows:

CEQA Finding # 1: *Significant impacts that cannot be substantially lessened or avoided.*

> Particulate emissions from operation of GOHF will add to existing violations of the State PM_{10} standard. PXP is required to provide mitigation for PM_{10} emissions as specified in the PM_{10} Emission Reduction Study. Implementation of these requirements was delayed by the APCD. The residual impact, after implementation of the permit conditions, is considered acceptable due to the local nature of the impact and the high background PM_{10} levels typical of coastal environments.

CEQA Finding #2: *Significant impacts have been eliminated or substantially lessened, where feasible, by implementation of all BACT requirements and air pollution controls proposed by the applicant.*

> Emissions of NO_x and ROCs from project components will lead to significant increases in ambient ozone concentrations, as NO_x and ROC are precursors to ozone formation. Ozone levels in excess of both the state and federal standards

are anticipated to occur. However, by providing offsets for project NO_x and ROC emissions, these impacts are effectively mitigated.

Emissions of SO_x from the flare were anticipated to cause exceedances of state 1 and 24-hour and federal 3-hour SO_2 ambient air quality standards during periods of amine and sulfur plant failures. However, PXP implemented a number of control devices as specified in the Phase II Flare Study which effectively mitigated these impacts.

CEQA Finding #3 The unavoidable significant impacts of the project are found to be acceptable due to overriding considerations.

Particulate emissions from GOHF result in a unavoidable significant adverse impact to air quality. However, offsets provided to mitigate NO_x and ROC emissions result in a net air quality benefit for these pollutants and are sufficient to outweigh the unavoidable environmental impact resulting from particulate emissions.

8.3 Lead Agency Permit Requirements

A Final Development Plan ("FDP") for the PXP Gaviota Development Project was approved by the Santa Barbara County Board of Supervisors. The approved Plan contains a number of provisions which relate to the air quality aspects of the proposed project. The following is a summary of major conditions and their relationship to the APCD's evaluation and final decision on the project.

FDP Condition E-2: Requirement for ATC prior to construction.

The issuance of the ATC permit fulfilled this requirement for the construction activities.

FDP Condition E-3/E-5: Requirement for preparation and implementation of Curtailment Plans for the protection of ambient air quality standards.

This requirement is no longer applicable.

FDP Condition E-4: Requirement for ambient air quality monitoring stations to examine onshore effects of construction and operation emissions.

Section 6.6, Ambient Monitoring identify the requirement for PXP to operate ambient air quality monitors during the project life.

FDP Condition E-6: Requirement for use of natural gas containing less than 6 ppm H_2S in gas turbines.

GOHF is limited to 4 ppmv total sulfur in the fuel gas.

FDP Conditions E-7 and E-9: Requirement that all NO_x and HC emissions that contribute to ozone standard violations be completely mitigated. Requires that PXP submit a plan based upon the letter agreements reached during the SCDP for project components on the OCS.

Compliance with emission mitigation requirements are discussed in Section 7. PXP has implemented the *Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Preliminary Development Plan No. 83-DP-32-CZ* (amended September 8, 1992) and the *OCS Ozone Mitigation Agreement* (dated September 8, 1992) in fulfillment of this requirement. Consolidation of OCS letters was achieved through the APCD approved *"OCS Control Measures, Recordkeeping, and Reporting Plan"*, dated (April 1993, updated February 1995). The elements of the plan have been incorporated directly into the platform Part-70 permits.

FDP Condition E-8: Cogeneration units can be used (up to the proposed 17.5 MW) provided that exceedances of local, state or federal ambient air quality standards do not occur, as determined by APCD-approved modeling of cumulative impacts. PXP shall equip the cogeneration unit stack with Continuous Emissions Monitoring and telemeter the data to the APCD offices.

The AQIA results (Section 6.1) show that the capacity of cogeneration facilities can be up to 17.5 MW without violating standards, providing that SCR is used. Permit conditions limit the cogeneration capacity and emissions and identify the requirement for Continuous Emissions Monitoring.

FDP Condition E-11: Requirement for data submission on helicopters, crew and supply boats.

Platform permits require submission of this data.

FDP Condition K-7: Prohibits visible smoke emissions during normal operations.

Compliance with APCD Rules 302 and 359 fulfills this condition.

FDP Condition P-12: Requires modification of construction schedule to prevent NO_2 standard violations during construction.

No longer applicable.

<u>FDP Condition A-21:</u> Requires mitigation of onshore air quality impacts from offshore operations, as projected through the AQAP update.

As described in Section 7.3PXP shall implement measures required by the *Contract for Implementation of Conditions E-4, E-7 and E-9 of the Chevron Point Arguello Preliminary Development Plan No. 83-DP-32-CZ* (amended September 8, 1992) and the *OCS Ozone Mitigation Agreement* (dated September 8, 1992).

9.0 Permit Conditions

This section lists the applicable permit conditions for this facility. 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., APCD only) permit conditions. Conditions listed in Sections A, B and C are enforceable by the USEPA, the APCD, the State of California and the public. Conditions listed in Section D are enforceable only by the APCD and the State of California. 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. In case of a discrepancy between the wording of a condition and the applicable federal or APCD rule(s), the wording of the rule 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 federally-enforceable administrative permit conditions apply to the GOHF:

A.1 **Condition Acceptance**. Acceptance of this operating permit by PXP shall be considered as acceptance of all terms, conditions, and limits of this permit.
[Re: ATC 5704]

A.2 **Grounds for Revocation**. Failure to abide by and faithfully comply with this permit shall constitute grounds for the APCO to petition for permit revocation pursuant to California Health & Safety Code Section 42307 *et seq*. *[Re: ATC 5704]*

A.3 **Defense of Permit**. PXP agrees, as a condition of the issuance and use of this PTO, to defend at its sole expense any action brought against the APCD because of issuance of this permit. PXP shall reimburse the APCD for any and all costs including, but not limited to, court costs and attorney's fees which the APCD may be required by a court to pay as a result of such action. The APCD may, at its sole discretion, participate in the defense of any such action, but such participation shall not relieve PXP of its obligation under this condition. The APCD shall bear its own expenses for its participation in the action. *[Re: ATC 5704]*

A.4 **Reimbursement of Costs**. All reasonable expenses, as defined in APCD Rule 210, incurred by the APCD, APCD contractors, and legal counsel for all activities related to the implementation of Regulation XIII (*Part 70 Operating Permits*) that follow the issuance of this PTO permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by PXP as required by Rule 210. *[Re: ATC 5704;Rule 210]*

A.5 **Access to Records and Facilities.** As to any condition that requires for its effective enforcement the inspection of records or facilities by the APCD or its agents, PXP shall make such records available or provide access to such facilities upon notice from the APCD. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. *[Re: ATC 5704]*

A.6 **Compliance.** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rules, regulations, ambient air quality standards or air quality increments. *[Re: ATC 5704]*

A.7 **Injunctive Relief.** In addition to any administrative remedies or enforcement provided hereunder, the APCD may seek and obtain temporary, preliminary, or permanent injunctive relief to prohibit violation of the conditions set forth herein or to mandate the conditions set forth herein or to mandate compliance with the conditions herein. All remedies and enforcement procedures set forth herein shall be in addition to any other legal or equitable remedies provided by law. *[Re: ATC 5704]*

A.8 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all written data, specifications and assumptions included with the application and supplements thereof (as documented in the APCD's project file), and with the APCD's analyses under which this permit is issued as documented in the permit analyses prepared for and issued with this permit.. *[Re: ATC 5704]*

A.9 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on this facility by the State of California or the California Coastal Commission in any consistency determination for the Project with the California Coastal Act. *[Re: ATC 5704]*

A.10 **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) Any permit noncompliance with sections 9.A, 9.B, or 9.C constitutes a violation of the Clean Air Act and is grounds for enforcement action; for permit termination, revocation and reissuance, or modification; or for denial of a permit renewal application.

(d) It shall not be a defense for the permittee in an enforcement action that it would have been necessary to halt or reduce the permitted activity in order to maintain compliance with the conditions of this permit.

(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 to the extent feasible. *[Re: 40 CFR Part 70.6.(a)(6), APCD Rule 1303.D.1]*

A.11 **Emergency Provisions.** The permittee shall comply with the requirements of the APCD, Rule 505 (Upset/Breakdown rule) and/or APCD 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 APCD, in writing, a "notice of emergency" within two (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: 40 CFR 70.6(g), APCD Rule 1303.F]

A.12 **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: APCD Rule 1302.D.2]

A.13 **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: APCD* Rule 1303.D.2]

A.14 **Severability.** In the event that any condition herein determined to be invalid, all other conditions shall remain in force.. *[Re: APCD Rules 103 and 1303.D.1]*

A.15 **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 APCD. 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 APCD rules.

The permittee shall apply for renewal of the Part 70 permit no later than 180-days before the permit expiration date. 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: APCD Rule 1304.D.1]*

A.16 **Payment of Fees.** The permittee shall reimburse the APCD for all its Part 70 permit processing and compliance 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 APCD and the USEPA pursuant to section 502(a) of the Clean Air Act.
[Re: APCD Rules 1303.D.1 and 1304.D.11, 40 CFR 70.6(a)(7)]

A.17 **Prompt Reporting of Deviations.** The permittee shall submit a written report to the APCD 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-day 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 APCD in accordance with Rule 505 *Breakdown Conditions,* or Rule 1303.F *Emergency Provisions. [APCD Rule 1303.D.1, 40 CFR 70.6(a) (3)]*

A.18 **Reporting Requirements/Compliance Certification.** The permittee shall submit compliance certification reports to the USEPA and the Control Officer every six months. These reports shall be submitted on APCD 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: APCD Rules 1303.D.1, 2.c; 1302.D.3]*

A.19 **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 APCD-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.20 **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 including calibration and maintenance records, shall be maintained for a minimum of five (5) years from date of initial entry by the permittee and shall be made available to the APCD upon request. *[Re: APCD Rule 1303.D.1.f, 40 CFR 70.6(a)(3)(ii)(A)]*

A.21 **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 APCD 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 APCD 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 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), 40 CFR 70.6(a)]

A.22 **Risk Management Plan – Section 112r.** PXP shall comply with the requirements of 40 CFR 68 on chemical accident prevention provisions. The annual compliance certification, if required, must include a statement regarding compliance with this part, including the registration and submission of the risk management plan (RMP).
[Re: 40 CFR 68]

9.B Generic Conditions

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. These conditions are federally enforceable. Compliance with these requirements is discussed in Section 3. In case of a discrepancy between the wording of a condition and the applicable federal or APCD rule(s), 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 APCD Rule 303. *[Re: APCD Rule 301]*

B.2 **Visible Emissions (Rule 302):** PXP 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 Ringlemann 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 flare (intermittent) and emergency firewater pump PXP shall determine compliance with this Condition/Rule, as specified below:

Intermittent Flare. For planned flaring, a visible emissions inspection for a one-minute period shall be performed once per quarter during a planned flaring event. For each unplanned flaring event exceeding four hours in duration, a visible emissions inspection for a one-minute period shall be performed. For both planned and unplanned events, if visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluation (VEE) shall immediately be performed. For planned flaring, the VEE shall be for a six-minute period or the duration of the flaring event, whichever is shorter. For unplanned flaring, the VEE shall be for six-minutes or the remaining duration of the flaring event beyond four hours, whichever is shorter.PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected.

Diesel ICEs and Turbines. Once per calendar quarter PXP shall perform a visible

emissions inspection for a one-minute period on each permitted and exempt engine or turbine, when operating. A VEE is not required for any turbine or turbine starter engine not operating on the day of the quarterly inspection. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluations (VEE) shall immediately be performed for a six-minute period.PXP staff certified in VEE shall perform the VEE and maintain logs in accordance with USEPA Method 9. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected.
PXP shall obtain APCD approval of the Visible Emissions Log required by this condition. All VEE sheets and records shall be maintained consistent with the recordkeeping condition of this permit.

For the purposes of this condition, "certified in VEE" shall mean that each individual assigned to perform a VEE has completed smoke school training and obtained certification in accordance with Method 9, section 3. Continued certification every six months is required. *[Re: APCD Rule 302]*

B.3 **Nuisance (Rule 303):** No pollutant emissions from any source at this facility shall create nuisance conditions. Operations shall not endanger health, safety or comfort, nor shall they damage any property or business. *[Re: APCD Rule 303]*

B.4 **PM Concentration – Southern Zone (Rule 305).** PXP shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in the PM concentrations listed in the table included in this rule. *[Re: APCD Rule 305]*

B.5 **Specific Contaminants (Rule 309):** PXP shall not discharge into the atmosphere from any single source sulfur compounds and combustion contaminants (particulate matter) in excess of the applicable standards listed in Sections A through E of Rule 309. *[Re: APCD Rule 309]*.

B.6 **Sulfur Content of Fuels (Rule 311).** PXP shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 238 ppmvd (50 gr/100 scf calculated as H_2S) for gaseous fuel. *[Re: APCD Rule 311]*

B.7 **Organic Solvents (Rule 317):** PXP shall comply with the emission standards listed in Rule 317.B. Compliance with this condition shall be based on PXP compliance with Condition 9.C.5 of this permit and facility inspections. *[Re: APCD Rule 317]*

B.8 **Metal Surface Coating Thinner and Reducer (Rule 322):** The use of photochemically reactive solvents as thinners or reducers in metal surface coatings is prohibited. Compliance with this condition shall be based on PXP compliance with Condition 9.C.5 of this permit and facility inspections. *[Re: APCD Rule 322]*

B.9 **Architectural Coatings (Rule 323):** PXP 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 PXP compliance with Condition 9.C.5 of this permit and facility inspections. *[Re: APCD Rules 323, 317, 322, 324]*

B.10 **Disposal and Evaporation of Solvents (Rule 324):** PXP 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 PXP compliance with Condition 9.C.5 of this permit and facility inspections. *[Re: APCD Rule 324]*

B.11 **Adhesives and Sealants (Rule 353)**: PXP 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 PXP uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353.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 recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. *[Re: APCD Rule 353]*

B.12 **Emergency Episode Plan**. During emergency episodes, PXP shall implement the APCD-approved June 2001 Emergency Episode Plan.

B.13 **Oil and Gas MACT.** PXP shall maintain records in accordance with 40 CFR Part 63, Subpart A--General Provisions, Sec. 63.10 (b)(3), to demonstrate the black oil exemption applies per 40 CFR 63.760(e)(1). *[Re: 40 CFR 63, Subpart HH]*

B.14 **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: APCD Rule 202]*

9.C Requirements and Equipment Specific Conditions

.C.1 **Combustion Equipment - Turbines/HRSG/SCR.** The following equipment are included in this emissions unit category:

EQ Device No.	Name
000998	Turbine G-10A (48.40 MMBtu/hr)/HRSG (54.78 MMBtu/hr)
000999	Turbine G-10B (48.40 MMBtu/hr)/HRSG (54.78 MMBtu/hr)
001000	Turbine G-10C (48.40 MMBtu/hr)/HRSG (54.78 MMBtu/hr)
001001	Turbine G-10D (48.40 MMBtu/hr)/HRSG (54.78 MMBtu/hr)
001002	Turbine G-10E (48.40 MMBtu/hr)/HRSG (54.78 MMBtu/hr)
001023	SCR (49.50 (MMBtu/hr)

(a) Emission Limits:

(i) Except during start-up and shutdown of the gas turbine, emissions from the common stack for the gas turbines, heat recovery steam generators and SCR duct burner [post selective catalytic reduction unit (SCR)] shall conform to BACT and shall not exceed the mass emission limits as listed in Tables 5.1 and 5.2. For the purposes of this condition, "startup "shall constitute the powering up of a turbine from a non-operating condition, i.e., zero fuel flow. "Shutdown" shall constitute the powering down of a turbine from a full operating condition to a non-operating condition, i.e., zero fuel flow.

(ii) Pound per hour (lb/hr) emission limits will be enforced based on the number of turbines, HRSG's, and SCR duct burners operating simultaneously. The maximum lb/hr limit is in accordance with the maximum operating scenario allowed by 9.C.1.b.ii (3 turbines, 2 HRSG units, and one duct burner).

(iii) Controlled NO_x concentrations from the common stack shall not exceed 19 ppmvd (as NO_2) at 3 percent O_2. During annual SCR cleaning described below, the above BACT and emission concentration limits do not apply, however, the mass emission limits remain enforceable.

(iv) The quarterly NO_x emissions from the cogeneration facility shall not exceed 8.07 tons including both the common stack and bypass stacks.

(v) During operation of a turbine, when the damper in the bypass stack is in the fully closed position, there will be some leakage of the turbine exhaust through the bypass stack. Such leakage emissions from the bypass stack shall not exceed 0.11 lb/hr of combined emissions of the respective turbine and auxiliary burner of NO_x (as NO_2) per turbine train's diverter stack.

(b) Operational Limits: The following operational limits apply:

(i) BACT controls for the cogeneration plant are defined as simultaneous injection of water and ammonia with SCR. PXP shall maintain, except during "start up and shut down" periods, a minimum water-to-turbine fuel ratio of 0.8:1 on a weight basis when operating in excess of 875 kW and an ammonia-to-SCR inlet NO_x ratio of 1.1:1.0±10 percent on a molar basis. Upon written approval by the APCD, PXP may elect to use different water injection or ammonia ratio once it has been demonstrated to the satisfaction of the APCD to result in an equivalent or lower NO_x emission rate than the ratios specified above. The compliance averaging times for water and ammonia injection shall be two consecutive 6-minute averages, i.e., two consecutive 6-minute data points outside the ratio limits for water or ammonia will constitute a violation.

(ii) PXP may operate a maximum of three (3) turbines, two (2) heat recovery steam generators (HRSG) and one (1) SCR duct burner simultaneously. Two turbines and two heat recovery steam generators shall remain out of service at all times consistent with permit condition 9.C.29. (Out of Service Equipment)

PXP shall provide the APCD a 12-hour notice prior to the start up of a fourth unit and shutdown of an active unit and identify the unit to be activated. Alternatively, the hourly fuel use for each turbine shall be provided for any day in which four or more units operated.

During the start up of an idle unit, which exceeds the maximum number of units allowed to operate, and shutdown of an active unit, simultaneous operation shall not occur. Simultaneous operation of more than three turbines or two HRSGs shall require an Authority to Construct to modify this permit consistent with the rules in effect at the time the application is deemed complete. Emission offsets shall be provided for the increased emissions resulting from simultaneous operation of these units.

(iii) Heat input (based on HHV) shall not exceed 48.40 MMBtu/hr for each turbine, 54.78 MMBtu/hr for each heat recovery steam generator and 49.50 MMBtu/hr for the SCR duct burner. Heating value records for any calendar day shall be made available for the APCD's inspection upon request. The total heat input for the turbines shall not exceed

145.2 MMBtu during any single hour. The total heat input for the turbine heat recovery steam generators shall not exceed 109.56 MMBtu during any single hour. For purposes of compliance determination the higher heating value shall be assumed to be 1100 Btu/scf. Heat input units are based on standard conditions.

(iv) The damper on each turbine diverter valve shall remain in a fully closed position during turbine operation, except during start-up and shutdown of the respective turbine, annual SCR cleaning and regulatory inspections in which regulatory personnel are onsite for an inspection requiring opening of the diverter valve. For safety reasons, diverter valves shall be open to the atmosphere when the turbine is not in service. Only one turbine may be started and one diverter valve may be open at any one time.

(v) Each diesel-fired turbine starter IC engine shall be operated for no more than 60 minutes per day, 10 hours per calendar quarter or 10 hours per calendar year. Notwithstanding the above, the total combined operation of all turbine starters may not exceed 2 hours per day.

(vi) The waste heat boiler auxiliary burner shall not be operating during start-up or shutdown of the respective turbine. In no case shall any diverter valve remain open and the respective turbine operating for greater than 30 minutes per start-up or shutdown. Annual SCR cleaning shall be permitted for one continuous 48 hour period per calendar year. For regulatory inspections described in 9.C.1(b)(iv) above, a diverter valve may remain open as long as necessary to complete the inspection. PXP shall inform the APCD, in writing, 8 hours prior to the commencement of this activity and within 24 hours of completion.

(vii) *Cogeneration Stack Flow Measurement Device*. For a one turbine operating case, if source tested stack flow rate is found to be beyond the ten percent required relative accuracy, PXP shall use a default value of 32,000 dscfm for determining stack flow rate at all loads.

(c) Monitoring: The following monitoring requirements shall apply:

(i) Annual source testing consistent with section 4.10, Table 4.4 and permit condition 9.C.15.

(ii) Monitoring of NO_x and CO emissions via CEMs, NH_3 and water injection rates and exhaust temperature consistent with section 4.9

and Table 4.3.

(iii) Monitoring of fuel use of each combustion unit per Table 4.3 for determination of permitted heat throughput limits.

(d) Recordkeeping: PXP shall maintain logs and records documenting compliance with the requirements of this condition (in a format approved by the APCD). These shall include:

(i) The amount of the natural gas burned each month in each turbine, HRSG and the duct burner.

(ii) Turbine Starters: ID number of the equipment; the number of operating minutes on each occurrence the engine is operated; and, the cumulative total monthly and annual hours. These shall be recorded through use of dedicated, non-resettable elapsed-time meters installed on each of these engines.

(iii) The amount of electricity generated, the amount consumed by the onshore facility and the amount provided to grid on a monthly basis.

(iv) Start-up and shutdown periods and periods when the diverter valve is open during turbine operation.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by permit condition 9.C.10 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re:ATC/PTO 9940; ATC/PTO 11203; 40 CFR 70.6]*

C.2 **Flaring Activities.** The following equipment is included in this emissions unit category:

EQ Device No.	Name
000996	48" Steam-assisted Peabody Flare

(a) Emission Limits: Mass emissions from the flare shall not exceed the limits listed in Tables 5.1 and 5.2. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits:

(i) *Flare SO_2 Reduction.* Total sulfur content (calculated as H_2S at standard conditions, 60° F and 14.7 psia) of the "planned continuous" gas flared at the GOHF shall not exceed 15.0 gr/100scf (238 ppmvd as H_2S at standard conditions).

(ii) *Water Seal.* The water seals serving the flare header shall be maintained in good working order when in service. The water seal serving the forty-two inch line is required to be in place at all times, however, the water seal serving the six-inch line is not required to be in service when chemical injection is occurring. While this water seal is out of service, the flare flow rate shall, at all times, be greater that one-half of the flare meter minimum detection level (MDL). The MDL of this meter is 576 scf/hr. During periods the six inch flare seal is removed, nitrogen purge or fuel gas purge shall be introduced into the flare header upstream of the flare flow meter and analyzers as necessary to maintain total flare flow rates above one-half the meter MDL.

(iii) Flare Purge/Pilot Fuel Gas Sulfur Limits. The total sulfur of the purge/pilot fuel gas combusted in the flare shall not exceed 10 ppmv total sulfur calculated as hydrogen sulfide (at standard conditions).

(iv) *Rule 359 Technology Based Standards.* Arguello shall comply with the technology based standards of Section D.2 of Rule 359. Compliance shall be based on monitoring and recordkeeping requirements of this permit as well as APCD inspections.

(v) *Flare Minimization/Flare Volume Monitoring Plans.* Arguello shall comply with all aspects of the subject plans. These plans are hereby incorporated by reference as part of this permit.

(c) Monitoring: Arguello shall monitor the following emission and process parameters for the flare relief system:

(i) Flare Volumes. The volumes of gas flared during each event shall be monitored by use of APCD-approved flare header flow meters. The meters shall be calibrated and operated consistent with the Process Monitor Calibration and Maintenance Plan.

(ii) The sulfur composition of flare gas shall be determined by draeger tube on a daily basis. During planned-infrequent and unplanned flaring events (including but not limited to pigging events and diversion of crude to T-2) an additional draeger sample shall be taken of the flare gas during the flare event.

(iii) The TRS of the flare gas shall be determined by the sampling procedures contained in the Flare Gas Sulfur Reporting Plan. Sampling shall be conducted annually to determine the non-H_2S reduced sulfur value.

(d) Recordkeeping: The following recordkeeping conditions shall apply:

(i) All flaring events shall be recorded in an APCD-approved log. The log shall include: date; duration of flaring events (start and stop times or start and duration times); quantity of gas flared; reason for flaring events; the type of event (e.g., planned or unplanned); the daily and flare event flare gas H_2S as determined by draeger tube; identification of which instrument is in use; the flare gas high heating value and the meter volume of flare gas for these events.

(ii) The volume of pilot/purge fuel gas combusted in the flare be recorded on a weekly, quarterly and annual basis.

(iii) All instances that the six inch flare line water seal is removed from service.

(iv) The volume of continuous flare gas shall be quantified separately for compliance purposes and all emissions data shall be reported similar to the current practice for unplanned events. A separate flare emissions summary report shall be provided for planned and unplanned flaring activity.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 359.H. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by permit condition 9.C.10 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re:ATC/PTO 11816; CFR 70.6]*

C.3 **Fugitive Hydrocarbon Inspection and Maintenance Program.**

(a) Emission Limits. Emissions from fugitive hydrocarbon components (e.g., valves and flanges) shall not exceed the emission limits set forth in Tables 5.1 and 5.2.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in APCD Rule 331.D and E. Compliance shall be assessed through the monitoring, recordkeeping and reporting conditions in this permit and facility inspections. In addition, the following shall apply:

(i) The vapor recovery and gas collection (VR&GC) systems at GOHF shall be in operation when equipment connected to these systems is in use. These systems include piping, valves, and flanges associated with the VR&GC systems. The VR&GC systems shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(ii) Implementation of an APCD-approved Fugitive I&M Plan for the GOHF for life of the project. The I&M Plan shall be consistent with the provisions of APCD Rule 331 and BACT requirements. Furthermore, PXP shall implement a BACT component identification system, including the use of component tagging, recordkeeping and reporting. The Plan, and any subsequent APCD approved revisions, is incorporated by reference as an enforceable part of this permit.

(iii) The total component and leakpath count listed in PXP most recent I&M component and leakpath inventory shall not exceed the total component and leakpath count listed in Table 5.2-1 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.

(iv) All routine venting of hydrocarbons shall be routed to either the flare header or other APCD-approved control device.

(v) PXP shall apply BACT, as defined in Table 4.1 for the life of the project. This requirement applies to components subject to the *de minimis* exemption of Rule 202 as well as projects that do not trigger the PXP threshold of Rule 802 and equivalent routine replacements.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in APCD Rule 331.F and the PXP Fugitive I&M Plan. The test methods in Rule 331.H shall be used, when applicable. In addition, PXP shall:

(i) Perform monthly monitoring of all valves.

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirements listed in APCD Rule 331.G and the approved I&M Plan. In addition, PXP shall:

(i) Record in a log the following: a record of leaking components found (including name, location, type of component, date of leak detection, the ppmv or drop-per-minute reading, date of repair attempts, method of detection, date of re-inspection and ppmv or drop-per-minute reading following repair); a record of the total components inspected and the total number and percentage found leaking by component type; a record of leaks from critical components; a record of leaks from components that incur five repair actions within a continuous 12-month period; and, a record of component repair actions including dates of component re-inspections.

(e) Reporting: The equipment listed in this section is subject to all the reporting requirements listed in APCD Rule 331.G and the I&M Plan, as applicable. On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by permit condition 9.C.10 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re:ATC/PTO 9940]*

C.4 **Tanks/Sumps.** The following equipment are included in this emissions category:

EQ Device No.	Name
TANKS	
000990	T-1 (Dry Oil)
000991	T-2 (Reject Oil)
008262	T-4 (Waste Water)
008263	T-8 (Wastewater)
008264	T-25 (Wastewater)
SUMPS	
101401	S-7 Drain Sump.

(a) Emission Limits: Emissions from the tanks and sump listed above shall not exceed the limits listed in Tables 5.1 and 5.2. The uncontrolled emissions from all tanks that are in service and required to be incorporated into the vapor recovery system, shall be controlled by a minimum of both:

(i) 95.0 percent by weight on a calendar day basis; and
(ii) 99.5 percent by weight on a calendar quarter and annual basis

utilizing the vapor recovery system at the plant. Compliance with this requirement shall be assessed according to: the procedures stated in the *Gaviota Heating Facility Vapor Recovery System - Control Efficiency Protocol* and applicable District Prohibitory rules.

(b) Operational Limits: All process operations from the tanks listed in this section shall meet the requirements of APCD Rule 325, Sections D, E, F and G. Compliance shall be assessed through the monitoring, recordkeeping and reporting conditions in this permit and facility inspections. In addition, the following shall apply:

(i) The following throughput limits shall apply to tank T-2:

(a) 120,000 barrels of fluids per day
(b) 12,000,000 barrels of fluids per year

(ii) The vapor recovery system shall be in operation when the equipment connected to the VRS system at the facility are in use. The VRS system includes piping, valves, and flanges. The VRS system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(iii) *NSPS Subpart Kb.* Operation shall be consistent with all applicable requirements of NSPS Subpart Kb.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of APCD Rule 325.H (for tanks) and NSPS Subpart Kb (for T-1 and T-2). The test methods outlined in APCD Rule 325.G and NSPS Subpart Kb shall be used, as applicable.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in APCD Rule 325.F (for tanks) and NSPS Subpart Kb (for T-1 and T-2). Arguello shall maintain hardcopy records for the information listed below:

(i) Daily and quarterly VRU efficiencies;
(ii) Record in a log on a daily basis the amount of oil throughput into the Dry Oil Tank (T-1) and the Reject Oil Tank (T-2) in units of barrels per day.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by permit condition 9.C.10 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 5704;PTO 5407-13; CFR 70.6]*

C.5 **Solvent Usage.** The following items are included in this emissions unit category: Photochemically reactive solvents, surface coatings and general solvents.

(a) Emission Limits: Emissions from solvent usage shall not exceed the emission limits listed in Tables 5.1 and 5.2. Additionally, the following solvent emission limits shall apply for the entire stationary source:

Device No.	Solvent Type	Lbs/hour	lbs/day
005867	Photochemically Reactive	8 lbs/hour	40 lbs/day
005867	Non-Photochemically Reactive	450 lbs/hour	3,000 lbs/day

(b) Operational Limits: Use of solvents for cleaning/degreasing shall conform to the requirements of APCD Rules 317, 322, 323 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and 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 discernable continuous flow of solvent.

(iv) *Solvent Good Operating Practice Plan:* PXP shall comply with all requirements of the APCD-approved *Solvent Good Operating Practice Plan.*

(c) Monitoring: none

(d) Recordkeeping: PXP 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 APCD-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 maintained in a manner readily accessible to APCD inspection.

(e) Reporting: On a semi-annual basis, a report detailing the previous six-month's activities shall be provided to the APCD. The report must list all data required by permit condition 9.C.10 (*Semi-Annual Compliance Verification Reports)* of this permit. *[Re: ATC 5704; APCD Rules 317, 322,323, 324]*

C.6 **Facility Use Limitations.** PXP shall process no more than 62,500 barrels per day of wet oil (emulsion) or generate no more than 10.5 megawatts of electricity (i.e., power output at standard conditions) under this permit. The oil processed under this permit shall be produced from the Point Arguello Field described in the Project EIS/EIR. At the request of PXP, the APCD may authorize the use of these facilities for oil produced from other areas or for the processing of larger volumes of oil than specified herein. Prior to issuing this authorization, the APCD shall make a determination that these changes will not result in the need to modify any permit conditions or modify any assumptions that were the basis of the analysis leading to issuance of this permit. PXP shall track in a log, on a daily basis, the actual usage data of the parameters limited by this condition (using an APCD-approved format). *[Re: ATC/PTO 10199]*

C.7 **Sulfur Recovery Unit Operational and Emission Limits**. PXP shall not process any natural gas at the GOHF. The Amine, Sulfur Recovery and Tail Gas Plants are no longer permitted by the APCD. *[Re:ATC/PTO 10199]*

C.8 **Offsets and Clean Air Plan Consistency.** PXP shall provide emission reduction credits to offset project emissions in the amounts listed in Table 5.1. The "Contract for Implementation of Conditions E-4, E-7 and E-9 of the Arguello/Point Arguello Preliminary Development Plan No. 83-DP-32-CZ" ("APCD/Arguello Contract") as amended on September 8, 1992 provides for mitigation of the entire project emissions which impact onshore air quality. PXP shall implement the APCD/Arguello Contract and the 1992 "OCS Ozone Mitigation Agreement" (and all subsequent amendments), which provides for reductions in offshore project emissions as well as application of additional controls on existing emission sources onshore and within State waters in order to mitigate the impact of OCS emissions. Through the implementation of the Contract and Agreement stated above, the APCD is able to make the finding that the project will result in a Net Air Quality Benefit and is consistent with the Clean Air Plan, as necessary for the issuance of this operating permit. PXP shall ensure that the emission reduction credits listed in Table 7.1-1, 7.1-2 and 7.1-3 are in place for the life of the project.

FLARE EMISSION INCREASE

Offsets for the flare emission increases are described in ERC ROC certificate No. 0018-0331. This certificate has been surrendered, cancelled and are dedicated to offsetting the flare emission increases.

C.9 **Recordkeeping.** All records and logs required by this permit and any applicable APCD, 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 GOHF. These records or logs shall be readily accessible and be made available to the APCD upon request. During this five year period, and pursuant to California Health & Safety Code Sections 42303 and 42304, such data shall be available to the APCD at GOHF within a reasonable time period after request by the APCD. This requirement applies to data required by this permit and archived by PXP and any other data-storage systems including but not limited to charts and manual logs. With the exception of processing monitoring data, prior to archiving any required data from the data-storage system, PXP shall prepare written reports and maintain these reports in an organized fashion at the plant. Failure to make such data available within the noted period shall be a violation of this condition. Further, retrieval of historical or archived data shall not jeopardize the logging of current data. *[Re: 40 CFR 70.6; APCD Rule 1303]*

C.10 **Semi-Annual Compliance Verification Reports.** Twice a year, PXP shall submit a compliance verification report to the APCD. 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 quarter). These reports shall be in a format approved by the APCD. All logs and other basic source data not included in the report shall be available to the APCD upon request. The second report shall also include an annual report for the prior four quarters. Pursuant to Rule 212, a completed *APCD Annual Emissions Inventory* questionnaire shall be included in the annual report or submitted electronically via the APCD website. The report shall include the following information:

(a) *Turbines/HRSG/SCR.*

(1) The amount of the natural gas burned each month in each turbine, HRSG and the duct burner.
(2) Turbine Starters: ID number of the equipment; the number of operating minutes on each occurrence the engine is operated; and, the cumulative total monthly and annual hours.
(3) The amount of electricity generated, the amount consumed by the onshore facility and the amount provided to grid on a monthly basis.
(4) All periods in which the diverter valve is open during turbine operation.

(b) *Fugitive Hydrocarbons*. Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis) to include the following:

(1) Inspection summary (including a record of the total components inspected and the total number and percentage found leaking by component type)
(2) Record of leaking components (including name, location, type of component, date of leak detection, the ppmv or drop-per-minute reading, date of repair attempts, method of detection, date of re-inspection and ppmv or drop-per-minute reading following repair)
(3) Record of leaks from critical components.
(4) Record of leaks from components that incur five repair actions within a continuous 12-month period.
(5) An updated FHC I&M inventory due to change in component list or diagrams.
(6) Listing of components installed as BACT as approved by the APCD.

(c) *Flaring.*

(1) The date; duration of flaring events (including start and stop times); quantity of gas flared; annual H_2S and TRS per third party analysis; value; reason for each flaring event, including the processing unit or equipment type involved and the type of event. The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year.
(2) The volume of pilot/purge fuel gas combusted in the flare be recorded on a weekly, quarterly and annual basis.
(3) All instances that the six inch flare line water seal is removed from service
(4) The volume of continuous flare gas shall be quantified separately for compliance purposes and all emissions data shall be reported similar to the current practice for unplanned events. A separate flare emissions summary report shall be provided for planned and unplanned flaring activity.

(d) *Tanks and Sumps*.

(1) daily and quarterly VRU efficiencies;
(2) Dates and the amount of oil sent to the reject oil tank (T-2) in units of barrels per day.
(3) Dates when the dry oil tank (T-1) is used and the amount of oil in barrels per day.

(e) *Surface Coatings and Solvent Usage***.** 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 APCD-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 maintained in a manner readily accessible to APCD inspection.

(f) *CEMs Report*. Data summaries for each parameter as per the APCD-approved CEM plan.
(1) Monitor downtime summary, including explanation and corrective action.
(2) Report on compliance with permit requirements, including any corrective action taken.

(g) *Vacuum Truck Usage*. Volume and description of material, reason for and duration of operation and all emission control device maintenance activities.

(h) *Chemical Injection*. The daily chemical injection rates, chemical type and dilution ratios for chemical injected into the fuel gas system and vapor recovery system.

(i) *Propane Use*. Each usage of propane in an APCD-approved format and shall maintain documentation of the sulfur content of each fuel shipment as certified in the fuel supplier's billing vouchers or through the analysis of a representative sample.

(j) *Vessel Purging*. All purging and inerting events which documents the following information: physical characteristics of the gas purged (such as sulfur concentration); purge time; equipment purged; control device used and the demonstrated efficiency of the control device.

(k) *Process Stream Sampling and Analysis*. Results from all process stream analyses.

(l) *Emergency Firewater Pump*. The number of operating hours of the firewater pump on each day the engine is operated; and, the cumulative total monthly and annual hours.

(m) *Process Monitor Calibration Report*. Summary of the date of calibration and results of each instrument.

(n) *Facility Throughput Data*. The volume of daily oil throughput and amount of electricity generated, used and delivered to grid.

(o) *Pigging*. Date and time of each pigging event.

(p) *Breakdown and Variances*. A summary of all breakdowns and variances including excess emissions.

(q) *Fuel Gas*.
- Quarterly fuel gas analysis of fuel gas higher heating value and TRS;
- Quarterly cylinder gas audit results for the fuel gas monitor;
- Instances fuel gas sulfur concentration trigger the high alarm.

(r) *H_2S Odor Sensor*.

1) Date and time of each incident in which the sensor alarm was activated including a full description of the incident;
2) For each incident in Item (1) above, a record of whether the existing plant personnel safety H_2S sensor alarms were activated during the incident;
3) All ventings from plant equipment including data and time, duration, associated alarms and whether the venting is maintenance/repair related;
4) Quarterly downtime and data capture rate for the H_2S monitoring system.
5) Results of the quarterly cylinder gas audits.

(s) *Emissions Reporting*.
- On an annual basis, NOx and ROC emissions from all exempt activities.
- Tons per quarter of all pollutants (by emissions unit) including supporting data.

(t) *General Reporting Requirements*.

(1) On quarterly basis, the emissions from each permitted emission unit for each criteria pollutant;
(2) On quarterly basis, the emissions from each exempt emission unit for each criteria pollutant;
(3) A summary of each and every occurrence of non-compliance with the provisions of this permit, APCD rules, NSPS and any other applicable air quality requirement;
(4) Information as required under the Standards of Performance for New Stationary Sources (40 CFR, Part 60);
(5) A copy of the Rule 202 De Minimis Log for the GOHF.
(6) Results of all process stream analyses.
(7) Diesel fuel shipments

The following reports shall be submitted on the frequencies indicated:

(u)*Ambient Air Quality Monitoring Report.* Submitted monthly consistent with the Ambient Air Quality Monitoring Plan.

(v)CEMs Downtime Report. Submitted quarterly, no later than forty-five days after the end of each quarterly.

[Re: ATC 5704; 40 CFR 70.6]

C.11 **BACT.** PXP shall apply emission control and plant design measures which represent Best Available Control Technology (BACT), to the operation of the GOHF facilities as described in Section 4.8 and Table 4.1 of this operating permit. BACT measures shall be in place and operation at all times for the life of the project.
[Re: ATC 5704]

C.12 **Ambient Air Quality Monitoring Program.** PXP shall operate the monitoring station listed in Table 6.6 for the life of the facility. PXP shall monitor and report the parameters listed in Table 6.6 in accordance with the APCD Air Quality and Meteorological Monitoring Protocol , the site-specific APCD-approved Monitoring Plan (April 5, 1995 for the Carpinteria station), the Quality Assurance/Quality Control (QA/QC) Document as submitted by PXP and APCD-approved updates to these documents. All data collected in Table 6.6 shall be telemetered to the APCD's Data Acquisition System on a real-time basis.

PXP shall reactivate the Gaviota East and West ambient air monitoring stations thirty days prior to the date actual dry oil rates at the GOHF exceed 50,000 BPD or as directed by the APCD following a determination that project emissions require such reactivation. The APCD shall be notified, in writing, of the intent to reactivate these stations. PXP shall be responsible for reactivation of these stations regardless of the source of the increased throughputs and operate them consistent with the original station operational requirements in accordance with the 1994 Monitoring Plan submitted by Tracer Technologies.

If deemed necessary by the APCD, PXP shall install additional monitoring stations to monitor upset/breakdown impacts. This requirement for additional monitoring stations may be appealed to the Air Pollution Control District Hearing Board by PXP solely to review the justification for the additional stations.

[Re: ATC 5704-10]

C.13 **Odor Monitoring Plan.** PXP shall implement the most recently issued APCD-approved Odor Monitoring Plan, This Plan is hereby incorporated by reference into this permit. The following specific requirements shall apply:

(a) H_2S Monitors.

1) PXP shall operate three gas monitors equipped to monitor H_2S. The make and model of these monitors, as well as the locations at which they are installed, are specified in the Odor Monitoring Plan. The monitors shall be equipped with sensor elements having a span of 0-10 ppmv.
2) A reading of 5 ppmv H_2S of any five second data point by any monitor shall constitute a violation of Rule 310 unless PXP can make the demonstration in Item (4) below.
3) Any monitor reading of 5 ppmv or greater shall trigger an alarm. The alarm shall be wired to the control room as either an audible or visual signal so that control room personnel located inside the control room or outside (and in the vicinity of the control room) are notified of the elevated H_2S readings.
4) PXP shall telephone (facsimile or email are acceptable if the telephone line is busy) the APCD Project Manager (or Project Inspector) within thirty (30) minutes of an alarm activation. A follow-up report shall be submitted in writing to the APCD within 24 hours providing details of the incident. If PXP believes the alarm is not attributable to the GOHF, the report shall demonstrate that the criteria established in the Odor Monitoring Plan for "incidents not attributable to the GOHF", have been satisfied. An alarm will be considered valid unless this demonstration shows that it is not attributable to the GOHF.
5) The H_2S monitoring system is required to meet an 80% data recovery rate. All one-minute and one-hour clock averages shall be recorded electronically.

(b) **Additional Monitoring.** Additional monitors may be required to be installed if more than two ventings from any tank or vessel occur in any given calendar year. The additional monitor(s) shall be installed within 30 days of written notification and approval by the APCD, or some other mutually agreed upon time period. A venting, as defined below, shall not be considered a venting for the purposes of installing additional monitors, if PXP can demonstrate to the satisfaction of the APCD, that there is no H_2S present in the vented hydrocarbons.

The additional monitors shall be comparable to, and operated consistent with, the monitors described listed in permit condition 9.C.13 and the approved Odor Monitoring Plan. A venting is defined as "the release of gaseous hydrocarbons to the atmosphere from any tank or vessel vent, hatch, or opening or any equipment item containing gaseous hydrocarbons". A venting shall include all releases except those associated with the proper maintenance, repair or replacement of a pressure relief device. A 12-hour advanced written notice shall be provided to the APCD prior to any venting associated with the scheduled repair or maintenance of a pressure relief device not requiring immediate attention.

(c) **Meteorological Data.** Meteorological data (wind and speed) shall be gathered on a continuous basis, except during calibration and maintenance or malfunction, by the existing *Wind Wizard* met station located at the control room. An electronic or mechanical record of the wind speed and direction data shall be maintained. Any change to this station shall be approved by the APCD prior to implementation. The monitor shall be calibrated at least every six months in accordance with manufacturers recommended procedures. A malfunctioning or inoperable monitor shall be repaired or replaced as soon as practicable.

PXP shall check the station daily to verify that the wind speed and direction monitors are operating properly. Monitor or recorder failure shall not constitute a permit violation provided that records of the failure (description, time, date, total downtime) are maintained.

(d) **Recordkeeping.** For any condition that requires for its effective enforcement, inspection of facility records or equipment by the APCD or its agents, PXP shall make such records available or provide access to such equipment upon notice from the APCD. Access to facilities shall mean access consistent with the California Health and Safety Code Section 41510 and Clean Air Act Section 114(a). At a minimum, the following records shall be maintained by the permittee and shall be made available to the APCD upon request:

1) Date and time of each incident in which the sensor alarm was activated including a full description of the incident;
2) For each incident in Item (1) above, a record of whether the existing plant personnel safety H_2S sensor alarms were activated during the incident;
3) All ventings from plant equipment including data and time, duration, associated alarms and whether the venting is maintenance/repair related;
4) Electronic or mechanical file of the continuous wind speed and direction data from the met station;
5) Calibration and Maintenance performed and all malfunctions (description, data and time) for the H_2S sensor and met station;
6) Electronic file of five-second H_2S data and storage of the latest 24 hours on the PXPSCADA system;
7) Quarterly downtime and data capture rate for the H_2S monitoring system.
8) Results of the quarterly cylinder gas audits

(e) **Abandonment of the Gaviota East and West Odor Monitoring Stations.** This permit does not authorize the abandonment and/or removal of the Gaviota East and West odor monitoring stations from the existing sites. PXP shall obtain approval from the Santa Barbara County Planning and Development Department prior to such removal and/or abandonment. *[Re:ATC/PTO 10332; 10332-01; 10332-02]*.

C.14 **Ambient Monitoring Station Data Review and Audit Fee.** Consistent with permit condition 9.C.12 of this permit, PXP shall operate ambient monitoring station and submit data to the APCD for quality assurance review and shall have the stations audited quarterly by APCD, or its contractor. In addition, PXP shall reimburse the APCD for the cost of this service. Effective July 1, 1999, PXP shall be assessed an annual fee, based on the District's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A, PXP shall pay fees specified in Table 9.C.14. The APCD will use this fee to pay staff costs to review and quality assure the monitoring data collected by PXP and the contractor or staff costs to audit the monitoring equipment. This fee shall not cover any District time necessary to issue or respond to any Notice of Violation, which will be billed on a reimbursable basis. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

In the event that PXP consistently requires services in excess of those assumed in the March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*), the Control Officer may move PXP to a reimbursable method of payment, subject to provisions of Rule 210. In the event that the assumptions used to establish this fee substantially increase or decrease, APCD may revisit and adjust the fee based on documentation of cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.C.14, which will become an enforceable part of the permit.

The fees prescribed in this condition shall expire if and when the Board adopts an Ambient Monitoring Station Data Review and Audit Fee and such fee becomes effective. *[Re: ATC 10152]*

Table 9.C.14. FEES for DATA REVIEW and AUDIT [(a) (b)]

FEE DESCRIPTION	FEE
Monitoring Station Data Review and Audit Fee	
Data review and audit activities associated with data submitted from any monitoring station in Table 6.6.	$23,569 annually

(a) All fees shall be due and payable pursuant to the governing provisions of Rule 210, including CPI adjustments.
(b) The fees in this table are based on the APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*) and may be updated pursuant to the requirements of this permit.

C.15 **Source Testing.** The following source test provisions shall apply:

(a) The permittee shall conduct source testing of air emissions and process parameters listed in Table 4.4. 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 APCD, occur. Source testing shall be performed on an annual schedule {Note: or biennial, triennial, as applicable} using May /June as the anniversary date.

(b) The permittee shall submit a written source test plan to the APCD for approval at least thirty (30) days prior to initiation of each source test. The source test plan shall be prepared consistent with the APCD's Source Test Procedures Manual (revised May 1990 and any subsequent revisions). The permittee shall obtain written APCD approval of the source test plan prior to commencement of source testing. The APCD shall be notified at least ten (10) calendar days prior to the start of source testing activity to arrange for a mutually agreeable source test date when APCD personnel may observe the test.

(c) Source test results shall be submitted to the APCD 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. Source test results shall document the permittee's compliance status with BACT requirements, mass emission rates in Section 5 and applicable permit conditions, rules and NSPS (if applicable). All APCD costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by the permittee as provided for by APCD Rule 210.

(d) 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 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 APCD approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. If the test can not be completed on the scheduled day, then the test shall be rescheduled for another time with prior authorization by the APCD. 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 APCD. Failing to perform the source test of an equipment item on the scheduled test day without a valid reason and without APCD's authorization shall constitute a violation of this permit. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the APCD by the close of the business day following the scheduled test day.

The timelines in (a), (b), and (c) above may be extended for good cause provided a written request is submitted to the APCD at least three (3) days in advance of the deadline, and approval for the extension is granted by the APCD.

C.16 **Chemical Injection.** The injection of chemical into the oil handling and vapor collection systems and fuel gas system, for the purpose of reducing the H_2S

concentration of the VRU vapors and fuel gas, shall be limited to the following chemical types: (1) BetzDM 5927 and (2) Nalco EC9022A. PXP shall inform the APCD, in writing, of the intent to inject any chemical other than these three chemicals and shall not be injected prior to District approval. An MSDS shall be provided concurrently with this notification. Records shall be maintained of the daily chemical injection rates, chemical type and dilution ratios. *[Re: ATC 10084; ATC 10394]*

C.17 **Produced Gas and Purging of Vessels.** PXP shall direct all produced gases to the vapor recovery system, the flare header or other permitted control device when de-gassing, purging or blowing down any tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds due to activities that include, but are not limited to, process or equipment turnarounds, process upsets or agency ordered safety tests.

PXP shall follow the most recently APCD-approved *Purging and Inerting Procedures* document ((PXP shall maintain an APCD-approved log of all purging and inerting events, not logged in the flaring log, which documents the following information:

- physical characteristics of the gas purged (such as sulfur concentration)
- purge time
- equipment purged
- control device used
- demonstrated efficiency of the control device *[Re: ATC 5704]*

C.18 **Complaint Response**. PXP shall provide the APCD with the name, title, current address, and 24-hour telephone number of contact person(s) who shall be available to respond to complaints from the public concerning nuisance or odors. These contact person(s) shall aid the APCD staff, as requested by the APCD, in the investigation of any complaints received. PXP shall take actions necessary to correct the facility activity which is reasonably believed by PXP to have caused the complaint. PXP shall keep the APCD fully apprised of their assessment and resolution of the problem. *[Re: ATC 5704]*

C.19 **Fuel Gas Sulfur Limit.** The sulfur content of fuel gas burned in the turbines or the flare as purge and pilot gas shall not exceed 10 ppmv total sulfur calculated as hydrogen sulfide (at standard conditions). The sulfur content of fuel gas burned in the auxiliary SCR heater and HRSG burners shall not exceed 4 ppm total sulfur calculated as hydrogen sulfide (at standard conditions). Compliance shall be based on an in-line continuous monitoring analyzer for analysis of the sulfur content of the fuel gas. This analyzer shall be located such that it is capable of monitoring any fuel gas used at the GOHF, including gas purchased from Socal. This analyzer shall be operated consistent with the requirements of the APCD's CEM Protocol document (dated March 21, 2001 and subsequent updates), where applicable, and the most recently APCD-approved Fuel Gas Sulfur Reporting Plan. The readings from this analyzer shall be adjusted upward to take into account the average non-hydrogen sulfide reduced sulfur compounds in the fuel gas consistent with the Fuel Gas Sulfur Reporting Plan. *[Re: ATC/PTO 11816]*

C.20 **Vacuum Truck Use.** During vacuum truck use, PXP shall use an APCD-approved control device to reduce emissions of odorous compounds from the vacuum truck vent. PXP shall maintain, and make available to the APCD upon request, a log of all vacuum truck operations. The log shall include the schedule, volume and description of material, reason for and duration of operation and emission control device maintenance activities. PXP shall follow the most recently APCD-approved *Vacuum Truck Plan*. An OVA, or other APCD-approved equipment, calibrated to methane shall be used to monitor ROC emissions from the carbon adsorption system exhaust, and the results (in units of ppmv) logged. The carbon canister shall be changed out within 10 calendar days if either of the following conditions exist: (a) the exhaust concentration level is 200 ppmv or greater, or (b) the canister has been used for 25 uses. *[Re: ATC 5704]*

C.21 **Diesel IC Engines - Particulate Matter Emissions.** To ensure compliance with APCD Rules 205.A, 302, 304, 309 and the California Health and Safety Code Section 41701, PXP shall comply with the most recently APCD-approved Diesel IC Engine Particulate Matter Operation and Maintenance Plan. This Plan details the manufacturer recommended maintenance and calibration schedules that PXP will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized. All diesel-fired engines, regardless of exemption status, shall be included in this Plan. *[Re: 40 CFR 70.6]*

C.22 **Continuous Emission Monitoring.** PXP shall implement a Continuous Emission Monitoring ("CEM") program for emissions and process parameters as specified in Section 4.9. Table 4.3 summarizes the parameters required to be monitored continuously, including those that are to be telemetered. CEM data shall be used by the APCD, alone or in combination with other data, to verify and enforce project conditions.

Any CEM associated with equipment that is removed from service may also be removed from service provided District approved procedures are implemented to assure the equipment is not inadvertently placed back in service. These procedures shall be submitted, in writing to the APCD and approved, prior to removal of the CEM from service. For any CEM listed in Table 4.3 that has been previously removed from service, the above procedures shall be submitted within thirty (30) days of the issuance of this permit.

PXP shall notify the APCD fourteen (14) days in advance of the proposed date of any shutdown equipment to be returned to service. All associated CEMs shall be operational prior to the startup of this equipment. Prior to the startup of this equipment a cylinder gas audit (CGA) shall be conducted on all concentration analyzers and a relative accuracy audit (RAA) shall be performed on all exhaust flow measurement devices within three weeks after startup of this equipment. If the equipment has been out of service for more than nine (9) months a relative accuracy test audit (RATA) shall also be performed within one month. These audits shall be consistent with the 40 CFR Appendix F and the APCD approved CEM Plan.

The monitoring devices shall meet the requirements set forth in APCD Rule 328, 40 CFR 51 and 40 CFR 60. Monitors must be installed, maintained, and operated in accordance with APCD and EPA requirements, as specified in the CFR and APCD-approved CEM Plan (APCD-approved Plan dated April 1, 1993), all subsequent revisions, and with manufacturer's specifications. Performance certification (relative accuracy testing and seven day calibration drift test) of the SO_x, NO_x, CO and O_2 analyzers shall occur at least once per year or more often if determined necessary by the APCD. PXP shall perform quarterly quality assurance audits as per 40 CFR 60, Appendix F on these analyzers. Additional continuous monitors or redundant systems may be required by the APCD if problems with the facility or the continuous monitors develop which warrant additional monitoring.

Minimum data reporting requirements shall be consistent with APCD Rule 328 and the approved CEM Plan and (as a minimum) must include the following:

- Data summaries for each parameter as per the APCD-approved CEM plan.
- Monitor downtime summary, including explanation and corrective action.
- Report on compliance with permit requirements, including any corrective action being taken.

In addition, operator log entries, strip charts, magnetic tapes, computer printouts, circular charts or diskettes, whichever is applicable, shall be provided upon request to the APCD. Pursuant to California HS&C §42706, PXP shall report all emission exceedances detected by the CEMS to the APCD within 96 hours of each occurrence. *[Re:ATC 10087]*

C.23 **Expiration of ERCs.** The ERCs subject to ERC Certificate No. 0045-1205 expire on December 14, 2010. Prior to the expiration of these ERCs, PXP shall secure substitute ERCs. Continued operations of the GOHF without securing APCD-approved ERCs shall constitute a violation of this permit. *[Re:PTO 5704-07]*.

C.24 **Mass Emission Limitations**. Mass emissions for each emissions unit associated with the GOHF shall not exceed the limits listed in Tables 5.1 and 5.2. *[Re: ATC 5704]*

C.25 **De-permitted Equipment.** All de-permitted equipment shall be permanently removed from service. Prior to permanent equipment removal, PXP may leave the equipment onsite provided this equipment is inerted and blinded off to the satisfaction of the APCD. Further, all equipment that remains designated as permitted shall be uniquely tagged and/or marked as permitted for the purpose of easily identifying this equipment during facility inspections. *[Re: ATC/PTO 10199-02]*

C.26 **Equipment Operating Restrictions.** Simultaneous operation of more than one oil train is prohibited. Two oil trains shall remain out of service consistent with Condition 28 at all times. PXP shall provide the APCD a 48-hour notice prior to the start up of an idle unit and identify the unit to be activated. During the startup of an idle unit and shutdown of an active unit, simultaneous operation shall not occur. Simultaneous operation of similar units shall require an Authority to Construct to modify this permit consistent with the rules in effect at the time the application is deemed complete. Emission offsets shall be provided for the increased potential emissions resulting from this Authority to Construct, if required by APCD rules.

Equipment items V-1BPCV-T30,T-5B and V-1500, P-1500A&B shall remain out of service at all times. Returning this equipment to service shall require an Authority to Construct to modify this permit consistent with the rules in effect at the time the application is deemed complete. Emission offsets shall be provided for the increased potential emissions resulting from this Authority to Construct, if required by APCD rules. *[Re: ATC/PTO 10199]*

C.27 **Out of Service Equipment.** Equipment listed in Table C.27 below that has been "removed from service" pursuant to ATC/PTO Permit No. 9933 (7/14/98) shall be maintained in a non-operational status and separated from in-service equipment (i.e., blind flanged) and purged/inerted consistent with the APCD-approved *Purging and Inerting Procedures* document (and all APCD-approved revisions). All such equipment that remains permitted shall be uniquely tagged and/or marked as permitted for the purpose of easily identifying this equipment during facility inspections.

Table C.27– EQUIPMENT
One Turbine/Two Turbine Fuel Systems[(a)]
One HRSG/Two HRSG Fuel Systems[(b)]
V-1B (free water knockout)
PCV-T30
T-6 (Wastewater)
T-7 (Wastewater)
T-9 (Wastewater)
T-10 (Wastewater)
T-5A (Wemco)
T-5B (Wemco)
V-1500 & P-1500A&B
Two Oil Trains[(c)]

a. One additional turbine was removed from service for NOx reductions and two turbine fuel systems were removed from service for fugitive ROC emission reductions per ATC/PTO 9933.
b. One HRSG was removed from service for NOx emission reductions and two HRSG fuel systems were removed from service for fugitive ROC emission reductions.
c. Includes V-2, V-3, exchangers E-1, E-2, E-3 and E-5 and associated piping. *[Re: ATC/PTO 10199]*

C.28. **Documents Incorporated by Reference.** PXP shall implement, and operate in accordance with, each of the plans listed below. The documents listed below, including any APCD-approved updates thereof, are incorporated herein and shall the full force and effect of a permit condition of this operating permit:

a) *Contract For Implementation of Conditions E-4, E-7, and E-9 of the Chevron/Point Arguello Project Preliminary Development Plan No. 83-DP-32-CZ", "Chevron's Final Development Plan* (August 19, 1985 and amended on September 8, 1992) *and the 1992 "OCS Ozone Mitigation Agreement" (and all subsequent amendments)*

b) *OCS Ozone Mitigation Agreement* (approved September 8, 1992 and the three subsequent amendments dated September 5, 1995; October 22, 1996 and May 20, 1997).

c) *Purging and Inerting Procedures Plan (revised and approved March 2001 2)*

d) *Vacuum Truck Plan ((revised and approved March 2001)*

e) *CEM Plan (revised and approved March 21, 2001)*

f) *Site-specific Ambient Air Monitoring Plan (April 5, 1995 for the Carpinteria station*)

g) *The Quality Assurance/Quality Control (QA/QC) Document* (approved May 11, 1994)

h) *The Cost Reimbursement Agreement for the Purchase and Installation of the APCD Central Data Acquisition System* (approved January 11, 1988)

i) *Rule 359 Flare Minimization Plan (revised and approved March 21, 2001)*

j) *Fugitive I&M Plan for the Gaviota Oil and Gas Plant (revised and approved March 21, 2001)*

k) *Odor Monitoring and Control Program Plan (approved April 5, 1995)*

l) *Odor Monitoring Plan (approved June 19, 2002)*

m) *Diesel IC Engine Particulate Matter Operation and Maintenance Plan (revised and approved March 21, 2001)*

n) *Process Monitor Calibration and Maintenance Plan (revised and approved March 21, 2001)*

o) *Fuel Gas Sulfur Reporting Plan (revised and approved March 21, 2001)*

p) *Flare Gas Sulfur Reporting Plan (revised and approved March 21, 2001)*

q) *S-4 Sump Plan (revised and approved March 21, 2001)*

r) *Vapor Recovery System Control Efficiency Protocol revised and (approved March 21, 2001)*

s) *Solvent Good Operating Practice Plan revised and (approved March 21, 2001)*

t) *Source Test Plan (revised and approved March 21, 2001) [Re: ATC 5704]*

9.D APCD-Only Conditions

D.1 **Mass Emission Limitations.** Mass emissions for the sumps and solvents shall not exceed the values listed in Tables 5.1, 5.2 and 5.4. *[Re: PTO 5704]*

D.2 **Standby/Emergency Diesel IC Engines.** The following equipment are included in this emissions unit category:

Device ID #	Device Name
107063	IC Engine: Emergency Standby Firewater Pump (267 bhp)

(a) Emission Limits: Emissions from these engines shall not exceed the emission limit standards (emission factors) listed in Table 5.1-2 or the mass limits 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. These limits are based on the maintenance and testing operational limits listed in permit condition 9.D.2(b)(i) below.

(b) Operational Limits: The equipment permitted herein is subject to the following operational restrictions listed below. Emergency use operations, as defined in Section (d)(25) of the ATCM[31], have no operational hours limitations.

(i) *Maintenance & Testing Use Limit:* The stationary emergency standby diesel-fueled CI engine(s) subject to this permit, shall limit maintenance and testing[32] operations to no more than 2 hours per day and 200 hours per year.

[31] 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

[32] "maintenance and testing" is defined in Section (d)(41) of the ATCM

(ii) *Fuel and Fuel Additive Requirements:* The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to the engine or any fuel tank directly attached to the engine.

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

(i) *Non-Resettable Hour Meter:* Each stationary 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 APCD 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 APCD staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to APCD staff within 5 working days from request. APCD 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
(iii) hours of operation for all uses other than for emergency use and maintenance and testing, along with a description of what those hours were for.

(iv) Fuel purchase records or a written statement on the fuel supplier's letterhead signed by an authorized representative of the company confirming that the fuel purchased is 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 *(Reference Stationary Diesel ATCM and Title 13, CCR, Sections 2281 and 2282).*

(v) The sulfur content of each fuel shipment as documented by fuel supplier records (e.g. billing vouchers or bills of laden). On an annual basis, the heating value of the diesel fuel (Btu/gal) shall be recorded based on measurement by DCOR or certified by the fuel supplier.

(e) **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 - vii) 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 APCD 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 shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD 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 shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD Engineering Supervisor;

(vii) Any engine in temporary replacement service shall be immediately shut down if the APCD 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.

(f) **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) of the ATCM shall notify the APCD immediately upon detection of the violation and shall be subject to APCD enforcement action.

(g) **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), shall notify the APCD 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 APCD.

D.3 **Turbine Starter Engines.** The following equipment are included in this emissions unit category:

Device ID #	**Device Name**
101263	IC Engine: Turbine Starter Engine (185 bhp)
101271	IC Engine: Turbine Starter Engine (185 bhp)
101272	IC Engine: Turbine Starter Engine (185 bhp)
101282	IC Engine: Turbine Starter Engine (185 bhp)
010283	IC Engine: Turbine Starter Engine (185 bhp)

(a) Emission Limits: Emissions from these engines shall not exceed the emission limit standards (emission factors) listed in Table 5.1-2 or the mass limits 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 Limits: The equipment permitted herein is subject to the following operational restrictions listed below.

(i) *Annual Use Limit:* Each engine shall not operate more that 10 hours per year.

(ii) *Fuel and Fuel Additive Requirements:* The permittee may only add CARB Diesel, or an alternative diesel fuel that meets the requirements of the ATCM Verification Procedure, or CARB Diesel fuel used with additives that meet the requirements of the ATCM Verification Procedure, or any combination of the above to the engine or any fuel tank directly attached to the engine.

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

(i) *Non-Resettable Hour Meter:* Each stationary 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 APCD 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 APCD staff upon request. Log entries made from 25 to 36 months from most recent entry shall be made available to APCD staff within 5 working days from request.

(i) emergency use hours of operation;

(ii) Fuel purchase records or a written statement on the fuel supplier's letterhead signed by an authorized representative of the company confirming that the fuel purchased is 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 *(Reference Stationary Diesel ATCM and Title 13, CCR, Sections 2281 and 2282).*

(iii)The sulfur content of each fuel shipment as documented by fuel supplier records (e.g. billing vouchers or bills of laden). On an annual basis, the heating value of the diesel fuel (Btu/gal) shall be recorded based on measurement by DCOR or certified by the fuel supplier.

(e) *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 - vii) 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 APCD 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 shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD 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 shall be sent electronically to: *temp-engine@sbcapcd.org* or may be transmitted in hardcopy to the ECD Engineering Supervisor;

(vii) Any engine in temporary replacement service shall be immediately shut down if the APCD 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.

(f) **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) of the ATCM shall notify the APCD immediately upon detection of the violation and shall be subject to APCD enforcement action.

(g) **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), shall notify the APCD 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 APCD.

D.4 **Process Stream Sampling and Analysis.** PXP shall sample and analyze the process streams listed in section 4.10. All process stream samples, except for TVP measurements, shall be taken according to APCD-approved ASTM methods and must be follow traceable chain of custody procedures. TVP samples shall be analyzed consistent with the requirements of Rule 325. PXP shall maintain logs and records documenting the results from all process stream analyses (in a format approved by the APCD). *[Re: PTO 5704]*

D.5 **Process Monitoring Systems.** All plant process monitoring devices listed in section 4.10 shall be properly operated and maintained according to the APCD- approved Process Monitor Calibration and Maintenance Plan. *[Re: PTO 5704]*

D.6 **Central Data Acquisition System.** PXP shall connect the Continuous Emission Monitors (CEM) and ambient and meteorological parameters listed in permit conditions 9.C.23 and 9.C.12, respectively, to the APCD central data acquisition system (DAS). In addition, PXP shall reimburse the APCD for the cost of operating and maintaining the DAS. PXP shall be assessed an annual fee, based on the APCD's fiscal year, collected semi-annually.

Pursuant to Rule 210 III.A., PXP shall pay fees specified in Table 9.D.4. The APCD shall use these fees to operate, maintain, and upgrade the DAS in proper running order. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

All ongoing costs and anticipated future capital upgrades will be APCD's responsibility and will be accomplished within the above stated DAS fee. This fee is intended to cover the annual operating budget and upgrades of the DAS and is intended to gradually phase APCD into a share of the DAS costs (as outlined in the March 27, 1998, letter – *Fixed Fee Proposal for Monitoring and DAS Costs*). In the event that the assumptions used to establish this fee substantially increase or decrease, APCD may revisit and adjust the fee based on documentation of cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.D.4.
The fees prescribed in this condition shall expire if and when the Board adopts a Data Acquisition System Operation and Maintenance Fee schedule and such fee becomes effective. *[Re:PTO 5704-05]*

Table 9.D.4. Fees for Data Acquisition System Operation and Maintenance (a) (b)

FEE DESCRIPTION	FEE
DATA ACQUISITION SYSTEM OPERATION AND MAINTENANCE FEE	
Per CEM, ambient or meteorological parameter required by permit to be transmitted real-time to the APCD Central Data Acquisition System	$1,273 annually

(a) All fees shall be due and payable pursuant to the governing provisions of Rule 210, including CPI adjustments.

(b) The fees in this table are based on the APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*) and may be updated pursuant to Rule 210 and shall be effective when issued and shall not require a modification to this permit.

D.7 **Abrasive Blasting Equipment.** All abrasive blasting activities performed at the GOHF and associated pipelines shall comply with the requirements of the California Administrative Code Title 17, Sections 92000 through 92530. PXP shall maintain logs and records documenting the emissions from all abrasive blasting operations. *[Re:PTO 5704]*

D.8 **Pigging Equipment.** PXP shall record in an APCD-approved log each pigging operation occurrence. The log shall include the date and pigging unit used. *[Re:PTO 5704]*

D.9 **Particulate Matter Mitigation.** PXP shall implement PM_{10} mitigation requirements specified by any future APCD PM_{10} Attainment Plan. The APCD will use, in part, the Particulate Matter Emission Reduction Study, dated June 1991, as a basis for development of control measures in the PM_{10} Attainment Plan. Within one year of notification by the APCD, PXP shall implement PM_{10} control measures identified in the future PM_{10} Attainment Plan on appropriate equipment regulated by APCD permits. *[Re: PTO 5704]*

D.10 **Recordkeeping.** The following records shall be maintained:

Abrasive Blasting. Logs and records documenting the emissions from all abrasive blasting operations.

D.11 **Diesel Fuel Sulfur Limit.** Diesel fuel used by the emergency firewater pump engine and turbine starter engines shall have a sulfur content of no greater than 0.0015 weight percent. PXP, Inc. shall maintain documentation of the sulfur content from each fuel supplier. *[Re: PTO 5704]*

D.12 **Use of Propane as Fuel Gas.** Propane may be used as an auxiliary fuel to the flare purge and pilot fuel gas on a temporary basis only during times when the supply of treated platform gas is interrupted. The propane shall meet Gas Processors Association specifications for propane (HD-5 grade) and shall have a total sulfur content no greater than 165 ppmv (10 gr/100 scf). PXP shall record in a log each usage of propane in an APCD-approved format and shall maintain documentation of the sulfur content of each fuel shipment as certified in the fuel supplier's billing vouchers or through the analysis of a representative sample. *[Re: PTO 5704]*

D.13 **S-4 Drain Sump.** Operation of this sump shall be consistent with the APCD-approved Drain Sump Monitoring and Maintenance Plan. *[Re:PTO 5407]*

D.14 **As-Built Drawings.** Upon request, PXP shall provide "as-built" drawings or acceptable facsimiles thereof, to the APCD or its agents. From time to time, the APCD shall review "as-built" drawings to determine conformance with the PTO, or with any other ATC application for this facility, submitted to the APCD. *[Re: PTO 5704]*

D.15 **Odorous Organic Sulfides (Rule 310):** PXP shall not discharge into the atmosphere H_2S or organic sulfides that result in a ground level impact beyond the PXP property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. Monitoring specified in condition 9.C.13 shall be used to assess compliance. [*Re: APCD Rule 310]*

AIR POLLUTION CONTROL OFFICER

____

____
Date

NOTES:

(a) Permit Reevaluation Due Date: July 2011
(b) Part 70 Operating Permit Expiration Date: July 2011

J. Menno	July 2008		
AQ Engineer	Date	Engineering Supervisor	Date

Attachments

10.1 Emission Calculation Documentation

10.2 IDS Tables

10.3 Equipment List

10.4 Valves in Gas Service/ Monthly Monitoring

10.5 Helicopter Emission Tables

10.6 PXP Comments on Draft Permit/ACPD Response

ATTACHMENT 10.1. Emission Calculation Documentation

Reference A - Combustion Engines

- The maximum operating schedule is in units of hours

- The default diesel fuel #2 characteristics are:
  density = 7.043 lb/gal (36EAPI)
  LHV = 18,410 Btu/lb (129,700 Btu/gal)
  HHV = 19,620 Btu/lb (138,200 Btu/gal)

- For crane engines:
  BSFC = 6,811 Btu/bhp-hr based on manufacturers specification
  energy based value using LHV
  Caterpillar 3408 DITA engine specification basis = 0.37 lb/hp-hr

- For turbine starter engines:
  BSFC = 6885 Btu/bhp-hr based on manufacturers specification
  energy based value using LHV
  Caterpillar 3208 engine specification basis = 0.374 lb/hp-hr

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

- LCF (LHV to HHV) value of 6 percent used.

- NO_x emission factor based on District Rule 333 limits
  $E_{lb\ NOx/MMBtu}$ = [(8.4 g/hp-hr)x(10^6)]) [(6811 Btu/hp-hr)x(1.06)x(453.6 g/lb)]

- ROC, CO and PM emission factors based on USEPA AP-42, Table 3.3-1 (7/93)

- SO_x emissions based on mass balance
  6 SO_x (as SO_2) = (%S) H (ρ_{oil}) H (20,000)) (HHV)

- PM_{10}:PM ratio = 0.96; ROC:TOC ratio = 1.0

- Allowable sulfur content of 0.0015 wt.%.

- Crane engine operational limits: General Equation

  Q = (BSFC) H (bhp) H (LCF) H (hours/time period)) (HHV, Btu/gal)

  East and West crane engines (each engine)
  Q= (6811 Btu/bhp-hr) H (475 bhp) H (1.06) H (24 hours/day)) (138,200 Btu/gal)
  = 596 gallons per day

  Q= (6,811 Btu/bhp-hr) H (475 bhp) H (1.06) H (800 hours/qtr)) (138,200 Btu/gal)
  = 19,851 gallons per quarter

Q= (6,811 Btu/bhp-hr) H (475 bhp) H (1.06) H (3200 hours/yr)) (138,200 Btu/gal)
= 79,406 gallons per year

Reference B - Combustion Flare

- The maximum operating schedule for the purge/pilot gas and planned continuous flaring is in units of hours

- The maximum operating schedule for the planned other and unplanned flaring is in units of percentage of annual usage

- Purge and pilot, planned, planned (continuous), and unplanned flow volumes and rates reported by Chevron

- HHV = 1,200 Btu/scf for purge & pilot gas

- HHV = 1,535 Btu/scf for all other flare gas

- Planned intermittent (other) and unplanned flaring events not calculated for short-term events per District policy

- The same emission factors are used for all flaring scenarios (except SO_x emissions)

- NO_x , ROC and CO emission factors based on USEPA AP-42, Table 11.5-1 (9/91)

- PM emission factor based on District Flare Study - Phase I Report, Table 3.1.1 (7/91)

- ROC:TOC ratio = 0.86; PM_{10}:PM ratio = 1.0

- SO_x emissions based on mass balance
  SO_x (as SO_2) = (0.169) X (ppmv S) / (HHV)

- Sulfur content of planned-continuous flared gas is 32,000 ppm_v.

- Sulfur content of planned-other and unplanned flared gas is 20,700 ppm_v.

- "Planned continuous flaring" value based on one half the minimum detection limit of the flare meter:

  - Flare meter: Fluid Components LT 81A mass flow detection
  - Minimum flow detection limit of flow element: 0.25 standard feet per second
  - HP Flare header outside: 14-inches (per Chevron July 18, 1994 letter)
  - HP Minimum detection limit: 862 scfh (per Chevron July 18, 1994 letter)
  - HP Half the minimum detection limit: 431 scfh

- LP Flare header outside: 16-inches (per Chevron July 18, 1994 letter)
- LP Minimum detection limit: 1,142 scfh (per Chevron July 18, 1994 letter)
- LP Half the minimum detection limit: 520 scfh
- Calculation spreadsheet backs out the purge volumes
- HP purge rate = 1,000 scfh; HP pilot rate = 140 scfh (per Chevron August 25, 1994 letter)
- LP purge rate = 540 scfh; LP pilot rate = 70 scfh

- No planned continuous flaring assessed as the LP and HP flare purge is greater than half the minimum detect value of each meter. All purge and pilot emissions (1,750 scfh for both flares) based on propane sulfur limit (165 ppmv S).

Reference C - Fugitive Components

- The maximum operating schedule is in units of hours

- All safe to monitor components are credited an 80-percent mass destruction rate efficiency. Unsafe to monitor components (as defined in Rule 331) are considered uncontrolled.

- Monthly monitoring of the valves qualifies for an Enhanced I&M credit. The APCD assigns a control efficiency of 84-percent for the regular valves for implementation of monthly monitoring. This is consistent with APCD P&P 6100.061 (Table 3), in that increasing the monitoring frequency from quarterly to monthly increases fugitive ROC control efficiency from 80-percent to 84-percent. The increased control effectiveness is assumed due to the fact that more frequent monitoring will both capture leaking valves and require that they be repaired to a leak-free state sooner than less frequent monitoring. Connections associated with the subject valves in the enhanced I&M program have a control efficiency of 82-percent.

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

- Leak-path counts are provided by applicant. The total count has been verified to be accurate within 5-percent of the District's P&ID and platform review/site checks.

- Emission factors based on the District/Tecolote Report, *Modeling of Fugitive Hydrocarbon Emissions* (1/86), Model B.

Reference D - Supply Boats

- The maximum operating schedule is in units of hours.
- Supply boat engine data based on a composite of the *M/V Victory Seahorse* and *M/V Santa Cruz*, with the largest engines on each boat used in the emission calculations.
- Two 2,500 bhp main engines (i.e., 5,000 bhp), two 300 bhp generator engines (i.e., 600 bhp) and one 515 bow thruster engine are utilized.
- Main engine load factor based on District *Crew and Supply Boat* study (6/87).
- Supply boat bow thruster engine only operates during maneuver mode.
- Supply boat generator engines provide half of total rated load; one generator engine operating continuously.
- The District has standardized the total time a supply boat operates (per trip) within 25 miles of platform to 11 hours. Typical trip is: 8 hours cruise, 2 hours maneuver and 1 hour idle. A trip includes time to, from and at the platform. Annual time based on 167 controlled trips. Spot-charter trips add about 184 hours.
- Main engine emission factors are based only on cruise mode values.
- The *M/V Victory Seahorse* main engines achieve a controlled NO_x emission rate of 8.4 g/bhp-hr through the use of turbo-charging, enhanced inter-cooling and 4° timing retard. This emission factor equates to 337 lb/1000 gallons.

  EF_{NOx} = (8.4 g/bhp-hr) / (0.055 gal/bhp-hr) / (453.6 g/lb) X (1,000)

  M/V Santa Cruz main engines achieve a controlled NO_x emission rate of 5.99 g/bhp-hr through the use of turbo-charging, enhanced inter-cooling and 4° timing retard. This emission factor equates to 270 lb/gal.

  EF_{NOx} = (5.99 g/bhp-hr) / (0.055 gal/bhp-hr) / (453.6 g/lb) X (1,000)

- Spot charter supply boat usage limited to 10-percent of actual annual controlled supply boat usage.
- Spot charter and Emergency Response vessels are uncontrolled for NO_x.
- Uncontrolled NO_x emission factor for main engines based on NO_x emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

  EF_{NOx} = (14 g/bhp-hr) / (0.055 gal/bhp-hr) / (453.6 g/lb) X (1,000)

- Uncontrolled ROC and CO emission factors for the main engines are based on USEPA AP-42, Volume II, Table II-3.3 (1/75) {cruise factor, 2500 bhp engine}.

- PM emission factor for the main engines are based on *Kelly, et. al.* (1981).

- PM_{10}:PM ratio = 0.96; ROC:TOC ratio = 1.0

- Sulfur content basis of 0.0015 wt %

- All SO_x emissions based on mass balance:

$$SO_x \text{ (as } SO_2) = (\%S) \text{ X } (\rho_{oil}) \text{ X } (20{,}000) / (HHV)$$

- Auxiliary and bow thruster engine emission factors (uncontrolled) are based on USEPA AP-42, Table 3.3-1 (7/93). Table emission factors converted to fuel basis using:

$$EF_{lb/1000\ gal} = (EF_{lb/MMBtu}) \text{ X } (19{,}300 \text{ Btu/lb}) \text{ X } (7.05 \text{ lb/gal}) / (1{,}000)$$

- Spot charter engine set-up assumed to be equal to main supply boat.

- Emergency response vessel is permanently assigned to Torch Platform Irene and Arguello Inc./Torch Platforms Hermosa, Hidalgo and Harvest. Vessel data provided by applicants. Short-term emissions from this vessel are not assessed. Long-term emissions are assessed equally amongst the four affected platforms.

- Emergency response vessel emissions calculated as an aggregate (main and auxiliary engines) using the uncontrolled supply boat emission factors. Total vessel bhp assumed to be 4,400 bhp. The long term hours of operating are back-calculated based on the fuel usage allocation for this platform of 20,000 gallons per year (80,000 gal/yr basis).

$$T_{yr} = \{(20{,}000 \text{ gal/yr}) / (0.055 \text{ gal/bhp-hr X } 4{,}400 \text{ bhp X } 0.65)\} = 127 \text{ hr/yr}$$

- Main and auxiliary engine operational limits: General Equation

$$Q = (BSFC) \text{ X } (bhp) \text{ X } (hours/time period) \text{ X } (load factor)$$

<u>Main engines:</u>

Q = (0.055 gal/bhp-hr) X (5,000 bhp) X (11 hours/day) X (0.65)
= 1,967 gallons per day

Q =(0.055 gal/bhp-hr) X (5,000 bhp) X (505 hours/qtr) X (0.65)
= 90,269 gallons per quarter

Q =(0.055 gal/bhp-hr) X (5,000 bhp) X (2,021 hours/yr) X (0.65)
= 361,254 gallons per year

Note: The quarterly and annual main engine hours include hours spent in controlled and uncontrolled operation.

Auxiliary engines – Generators:

Q = (0.055 gal/bhp-hr) X (600 bhp) X (11 hours/day) X (0.50)
= 182 gallons per day

Q =(0.055 gal/bhp-hr) X (600 bhp) X (459 hours/qtr) X (0.50)
= 7,574 gallons per quarter

Q =(0.055 gal/bhp-hr) X (600 bhp) X (1,837 hours/yr) X (0.50)
= 30,311 gallons per year

Auxiliary engines - Bow Thruster:

Q = (0.055 gal/bhp-hr) X (515 bhp) X (2 hours/day)
= 57 gallons per day

Q = (0.055 gal/bhp-hr) X (515 bhp) X (78 hours/qtr)
= 2,210 gallons per quarter

Q = (0.055 gal/bhp-hr) X (515 bhp) X (312 hours/yr)
= 8,838 gallons per year

Reference E - Crew Boat

- The maximum operating schedule is in units of hours
- Crew boat engine data based on M/V *Price Tide*
- Three 510 bhp main engines (i.e., 1,530 bhp), one 218 bhp auxiliary engines are utilized. No bow thruster engines are on board.
- Main engine load factor based on District *Crew and Supply Boat* study (6/87)
- Crew boat auxiliary engines provide half of total rated load; auxiliary engine is operating continuously
- Total time crew boat operate per trip within 25 miles of platform is 11 hours. A trip includes time to, from and at the platform. Typical trip is: 8 hours cruise, 2 hours maneuver and 1 hour idle. Annual time based on 8 controlled trips and one spot charter trip.

- Main engine emission factors are based only on cruise mode values.

- Crew boat main engines achieve a controlled NO_x emission rate of 8.4 g/bhp-hr through the use of turbo-charging, inter-cooling and 4° timing retard. This emission factor equates to 337 lb/1000 gallons.

  $$EF_{NOx} = (8.4 \text{ g/bhp-hr}) / (0.055 \text{ gal/bhp-hr}) / (453.6 \text{ g/lb}) \text{ X } (1000)$$

- Spot charter crew boat usage limited to 1 platform trip per year.

- Spot charter normally is uncontrolled for NO_x .

- Uncontrolled NO_x emission factor for main engines based on NO_x emission rate of 14 g/bhp-hr

- Uncontrolled ROC and CO emission factors for the main engines are based on USEPA AP-42, Volume II, Table II-3.3 (1/75) {cruise factor, 500 bhp engine}

- PM emission factor for the main engines are based on *Kelly, et. al.* (1981)

- PM_{10}:PM ratio = 0.96; ROC:TOC ratio = 1.0

- All SO_x emissions based on mass balance

  $$SO_x \text{ (as } SO_2) = (\%S) \text{ X } (\rho_{oil}) \text{ X } (20{,}000) / (\text{HHV})$$

- Auxiliary engine emission factors (uncontrolled) are based on USEPA AP-42, Table 3.3-1 (7/93). Table emission factors converted to fuel basis using:

  $$EF_{lb/1000 \text{ gal}} = (EF_{lb/MMBtu}) \text{ X } (19{,}300 \text{ Btu/lb}) \text{ X } (7.05 \text{ lb/gal}) / (1000)$$

- Spot charter engine set-up assumed to be equal to main crew boat engine set-up.

- Main and auxiliary engine operational limits: General Equation

  Q = (BSFC) X (bhp) X (hours/time period) X (load factor)

  Main engines

  Q = (0.055 gal/bhp-hr) X (1,530 bhp) X (11 hours/day) X (0.85)
  = 787 gallons per day

  Q =(0.055 gal/bhp-hr) X (1,530 bhp) X (33 hours/qtr) X (0.85)
  = 2,361 gallons per quarter

  Q =(0.055 gal/bhp-hr) X (1,530 bhp) X (99 hours/yr) X (0.85)
  = 7,081 gallons per year

Auxiliary engines

Q = (0.055 gal/bhp-hr) X (218 bhp) X (11 hours/day) X (0.50)
= 66 gallons per day

Q =(0.055 gal/bhp-hr) X (218 bhp) X (22 hours/qtr) X (0.50)
= 132 gallons per quarter

Q =(0.055 gal/bhp-hr) X (218 bhp) X (88 hours/yr) X (0.50)
= 528 gallons per year

Reference F - Pigging Equipment

- Maximum operating schedule is in units of events
- Gas and oil launcher volume, pressures and temperatures based on application
- All gas in launchers is blown down to the flare relief system prior to opening the vessel to the atmosphere
- The remaining vessel pressure is assumed to be no greater than 5 psig. It is assumed that the volume of gas released during the opening of the vessel is equal to the volume of the vessel. The temperature of the remaining vapor in both vessels = 100°F (per applcn)
- The MW_{gas} = 23 lb/lb-mol (gas launcher) and MW_{oil} = 50 lb/lb-mol (oil launcher)
- Average ROC weight % = 0.37
- Calculate a site vessel specific emission factor using the ideal gas law and the volume of the vessel in units of "lb ROC/acf-event"

$\rho = (P_{ves} \text{ X } MW) / (R \text{ X } T)$, density of vapor remaining in vessel (lb VOC/acf)

$EF = (\rho \text{ X } V_{ves} \text{ X ROC wt. \%})$, (lb ROC/acf-event)

Reference G - Sumps/Tanks/Separators

- Maximum operating schedule is in units of events
- Emission calculation methodology based on the CARB/KVB report *Emissions Characteristics of Crude Oil Production Operations in California* (1/83)

- Sump calculations are based on surface area of emissions unit as supplied by the applicant

- Oil/water separator calculations are based on gallons of oily water throughput

- All emission units are classified as secondary production and heavy oil service

Reference H - Solvents

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

- Daily, quarterly and annual emission rates per application

- Hourly emissions based on daily value divided by an average 8-hour day. Compliance with hourly data to be based on daily actual usage divided by 8.

Reference I - Turbines

- The maximum operating schedule is in units of hours

- Refer to section 4 for general calculation equations for NO_x, ROC, and CO

- Emission factors for SO_2 and PM are found in EPA AP-42, Table 3.1-1

- PM_{10}/PM ratio = 0.96; ROC/TOC ratio = 1.0

- Emission calculations are based upon turbine operating at max load

- General Equation for Turbine Operational Limits:

  Q = (BSFC) X (kW) X (FCF) X (hours/time period) / (HHV, Btu/scf or gal)

  For Turbine G-91 (NG)

  Q = (14,581 Btu/kW-hr) x (2,800 kW) x (1.10) x (24 hours/day) / (1,150 Btu/scf)
  = 937,241 scf per day

  Q= (937,241 scf/day) / (24 hours/day) *(550 hr/qtr) = 21.478 million scf per qtr

  Q= (937,241 scf/day) / (24 hours/day) *(550 hr/yr) = 21.478 million scf per year

For Turbines G-92, G93 (NG)

Fuel Gas - Per Turbine

Q = (14,581 Btu/kW-hr) x (2,800 kW) x (1.10) x (24 hours/day) / (1,150 Btu/scf)
= 937,241 scf per day

Q = (14,581 Btu/kW-hr) x (2,800 kW) x (1.10) x (2,190 hours/qtr) / (1,150 Btu/scf)
= 85.523 million scf per quarter

Q = (14,581 Btu/kW-hr) x (2,800 kW) x (1.10) x (8,760 hours/yr) / (1,150 Btu/scf)
= 342.093 million scf per year

For Turbine G-94 (NG)

Q = (14,371 Btu/kW-hr) x (3,100 kW) x (1.10) x (24 hours/day) / (1,150 Btu/scf)
= 1,022,715 scf per day

Q = (14,371 Btu/kW-hr) x (3,100 kW) x (1.10) x (2,190 hours/qtr) / (1,150 Btu/scf)
= 93.323 million scf per quarter

Q = (14,371 Btu/kW-hr) x (3,100 kW) x (1.10) x (8,760 hours/yr) / (1,150 Btu/scf)
= 373.291million scf per year

For Turbines (G-91 and G-93 (Diesel)

Q = (14,581 Btu/kW-hr) X (2,800 kW) X (1.06) X (24 hours/day) / (138,200 Btu/gal)
= 7,515 gallons per day

Q = (14,581 Btu/kW-hr) X (2,800 kW) X (1.06) X (875 hours/qtr) / (138,200 Btu/gal)
= 274,001 gallons per quarter

Q = (14,581 Btu/kW-hr) X (2,800 kW) X (1.06) X (1750 hours/yr) / (138,200 Btu/gal)
= 548,001 gallons per year

For Turbine G-92 (Diesel)

Q = (14,581 Btu/kW-hr) x (2,800 kW) x (1.06) x (24 hours/day) / (138,200 Btu/gal)
= 7,515 gallons per day

Q= (7,515 gal/day) / (24 hours/day) *(600 hr/yr) = 187,875 gal per qtr

Q= (7,515 gal/day) / (24 hours/day) * (6000 hr/yr) = 187,875 gal per year

Reference J - Starter Engines

- The maximum operating schedule is in units of hours
- Emission factors are from EPA AP-42, Table 3.3-1
- It is assumed that each turbine startup lasts no longer than 15 minutes

ATTACHMENT 10.2. IDS Database Emission Tables

Table 10.2-1
Permitted Potential to Emit (PPTE)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9105 – Pt-70 Permit to Operate						
lb/hour	238.40	34.41	68.03	2.27	20.58	20.00
lb/day	2789.58	526.69	1119.87	8.69	308.82	302.55
tons/qtr	52.51	16.62	31.38	6.65	5.71	5.60
tons/year	204.15	61.36	94.54	26.49	17.77	17.34

Table 10.2-2
Facility Potential to Emit (FPTE)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9105 – Pt-70 Permit to Operate						
lb/hour	238.40	34.41	68.03	2.27	20.58	20.00
lb/day	2789.58	526.69	1119.87	8.69	308.82	302.55
tons/qtr	52.51	16.62	31.38	6.65	5.71	5.60
tons/year	204.15	61.36	94.54	26.49	17.77	17.34

Table 10.2-3
Facility Net Emission Increase Since 1990 (FNEI-90)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9105 – Pt-70 Permit to Operate						
Lb/day	14.48	1.24	64.32	3.94	1.04	1.01
Tons/year			7.44	4.45		

Table 10.2-4

<u>Stationary Source Net Emission Increase Since 1990 (FNEI-90)</u>

Facility	NO_x	ROC	CO	SO_x	TSP	PM_{10}
GOHF						
lbs/day	209.29	376.65	455.55	8.66	70.69	70.69
tons/year	36.01	51.48	91.91	3.92	13.11	13.11
Platform Harvest						
lbs/day		1.94		1.19		
tons/year		0.32		0.22		
Platform Hermosa						
lbs/day	0.71	6.37	62.88	0.72	0.21	0.21
tons/year	0.13	1.02	8.14	0.13	0.04	0.04
Platform Hidalgo						
lbs/day	14.48	1.24	64.32	3.94	1.04	1.01
tons/year			7.44	4.45		
Total						
lbs/day	224.48	386.20	582.75	14.51	70.73	70.73
tons/year	36.14	52.82	107.49	8.72	13.15	13.15

ATTACHMENT 10.3. Equipment List

Thursday, July 24, 2008
Santa Barbara County APCD – Equipment List

PT-70/Reeval 05704 R3 / FID: 01325 Gaviota Oil Heating Facility / SSID: 01325

A PERMITTED EQUIPMENT

1 Stationary Internal Combustion Engines (Table A)

1.1 Diesel Starter Motor

Device ID #	**101271**	***Device Name***	**Diesel Starter Motor**
Rated Heat Input		*Physical Size*	185.00 Brake Horsepower
Manufacturer	Detroit Diesel (GM)	*Operator ID*	A-002
Model	453 T 5043801	*Serial Number*	1-XF-A S/N 4D-0211640
Location Note	A-10A		
Device Description	Engine Use: Starter motor Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Cyclic Device Grouping No: FP-5-026-B Device SCC No: 2-02-001-02 Max Operating Hrs: 0.5/da;10/qtr;10/yr		

1.2 Diesel Starter Motor

Device ID #	**101263**	***Device Name***	**Diesel Starter Motor**
Rated Heat Input		*Physical Size*	185.00 Brake Horsepower
Manufacturer	Detroit Diesel (GM)	*Operator ID*	A-001
Model	453 T 5043801	*Serial Number*	1-XF-A S/N 4D-0211635
Location Note	A-10A (G10A)		
Device Description	Engine Use: Starter motor Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Cyclic Device Grouping No: FP-5-026-B		

Device SCC No: 2-02-001-02
Max Operating Hrs: 0.5/da;10/qtr;10/yr

1.3 Diesel Starter Motor

Device ID #	**101272**	***Device Name***	**Diesel Starter Motor**
Rated Heat Input		*Physical Size*	185.00 Brake Horsepower
Manufacturer	Detroit Diesel (GM)	*Operator ID*	A-003
Model	453 T 5043801	*Serial Number*	1-XF-A S/N 4D-0211645
Location Note	A-10		
Device Description	Engine Use: Starter motor Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Cyclic Device Grouping No: FP-5-026-B Device SCC No: 2-02-001-02 Max Operating Hrs: 0.5/da;10/qtr;10/yr		

1.4 Diesel Starter Motor

Device ID #	**101282**	***Device Name***	**Diesel Starter Motor**
Rated Heat Input		*Physical Size*	185.00 Brake Horsepower
Manufacturer	Detroit Diesel (GM)	*Operator ID*	A-004
Model	453 T 5043801	*Serial Number*	1-XF-A S/N 4D-0211643
Location Note	A-10A		
Device Description	Engine Use: Starter motor Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Cyclic Device Grouping No: FP-5-026-B Device SCC No: 2-02-001-02 Max Operating Hrs: 0.5/da;10/qtr;10/yr		

1.5 Diesel Starter Motor

Device ID #	**101283**	***Device Name***	**Diesel Starter Motor**
Rated Heat Input		*Physical Size*	185.00 Brake Horsepower
Manufacturer	Detroit Diesel (GM)	*Operator ID*	A-005
Model	453 T 5043801	*Serial Number*	1-XF-A S/N 4D-0211638
Location Note	A-10A		
Device Description	Engine Use: Starter motor Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Cyclic Device Grouping No: FP-5-026-B Device SCC No: 2-02-001-02 Max Operating Hrs: 0.5/da;10/qtr;10/yr		

2 External Combustion (Table B)

2.1 Heat Recovery Steam Generator (G-10A)

Device ID #	**006518**	***Device Name***	**Heat Recovery Steam Generator (G-10A)**
Rated Heat Input	54.780 MMBtu/Hour	*Physical Size*	54.78 MMBtu/Hour
Manufacturer	Struthers/Coen	*Operator ID*	B-001
Model		*Serial Number*	F-10A S/N 84-03-51019-1
Location Note	A-10A		
Device Description	Equipment Use: Steam Generation Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H_2S Equipment Type: Steam Generator Device Grouping No: F-100005-12 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

2.2 Heat Recovery Steam Generators (G-10B)

Device ID #	**006519**	***Device Name***	**Heat Recovery Steam Generators (G-10B)**
Rated Heat Input	54.780 MMBtu/Hour	*Physical Size*	54.78 MMBtu/Hour
Manufacturer	Struthers/Coen	*Operator ID*	B-002
Model		*Serial Number*	F-10A S/N 84-03-51019-2
Location Note	A-10A		
Device Description	Equipment Use: Steam Generation Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Steam Generator Device Grouping No: F-100006-12 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

2.3 Heat Recovery Steam Generators (G-10C)

Device ID #	**006520**	***Device Name***	**Heat Recovery Steam Generators (G-10C)**
Rated Heat Input	54.780 MMBtu/Hour	*Physical Size*	54.78 MMBtu/Hour
Manufacturer	Struthers/Coen	*Operator ID*	B-003
Model		*Serial Number*	F-10A S/N 84-03-51019-3
Location Note	A-10A		
Device Description	Equipment Use: Steam Generation Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Steam Generator Device Grouping No: F-100007-12 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

2.4 Heat Recovery Steam Generators (G-10D)

Device ID #	**006521**	***Device Name***	**Heat Recovery Steam Generators (G-10D)**
Rated Heat Input	54.780 MMBtu/Hour	*Physical Size*	54.78 MMBtu/Hour
Manufacturer	Struthers/Coen	*Operator ID*	B-004
Model		*Serial Number*	F-10A S/N 84-03-51019-4
Location Note	A-10A		
Device Description	Equipment Use: Steam Generation Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Steam Generator Device Grouping No: F-100011-10 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

2.5 Heat Recovery Steam Generators (G-10E)

Device ID #	**006522**	***Device Name***	**Heat Recovery Steam Generators (G-10E)**
Rated Heat Input	54.780 MMBtu/Hour	*Physical Size*	54.78 MMBtu/Hour
Manufacturer	Struthers/Coen	*Operator ID*	B-005
Model		*Serial Number*	F-10A S/N 84-03-51019-5
Location Note	A-10A		
Device Description	Equipment Use: Steam Generation Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Steam Generator Device Grouping No: F-100012-10 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

2.6 SCR Duct Burner

Device ID #	**001023**	***Device Name***	**SCR Duct Burner**
Rated Heat Input	49.500 MMBtu/Hour	*Physical Size*	
Manufacturer	Entec/Coen	*Operator ID*	B-006
Model		*Serial Number*	F-500 S/N
Location Note	A-10B		
Device Description	Equipment Use: Heater Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H_2S Equipment Type: SCR Duct Burner Device Grouping No: D-106007-4 Device SCC No: 2-01-001-02 Max Operating Hrs: 8760/yr Emission Control: SCR (80% Mass DRE)		

3 Fixed Roof Storage Tanks (Table C)

3.1 Reject Oil Tank

Device ID #	**000991**	***Device Name***	**Reject Oil Tank**
Rated Heat Input		*Physical Size*	1680000.00 Gallons
Manufacturer	San Luis Tank	*Operator ID*	C-015
Model		*Serial Number*	T-2 (S/N 2620)
Location Note	A-03B		
Device Description	Equipment Use: Reject Tank Tank/roof Type: Vertical/Cone Roof Tank Dia x Hgt (ft): 80 x 48 Roof Height (ft): 1 Avg Liquid Hgt (ft): 24 Annual Net Throughput (bbl/yr): 1,200,00 Daily Max Throughput (bbl/da): 120,000 Annual Turnovers: 30 Device Grouping No: F-30011-24 Device SCC No: unknown Max Operating Hrs: 8760/yr Emission Control: Vapor Recovery (99.5%eff)		

3.2 Dry Oil Tank

Device ID #	**000990**	***Device Name***	**Dry Oil Tank**
Rated Heat Input		*Physical Size*	420000.00 Gallons
Manufacturer	San Luis Tank	*Operator ID*	C-014
Model		*Serial Number*	T-1 (S/N 2619)
Location Note	A-03B		
Device Description	Equipment Use: Shipping Tank Tank/roof Type: Vertical/Cone Roof Tank Dia x Hgt (ft): 55 x 24 Roof Height (ft): 1 Avg Liquid Hgt (ft): 12 Annual Net Throughput (bbl/yr): 36,500,000 Daily Max Throughput (bbl/da): 100,000 Annual Turnovers: 3850 Device Grouping No: F-30010-16 Device SCC No: unknown Max Operating Hrs: 8760/yr Emission Control: Vapor Recovery (99.5%eff)		

3.3 Cooling Water

Device ID #	**107821**	***Device Name***	**Cooling Water**
Rated Heat Input		*Physical Size*	2262.00 Square Feet Area
Manufacturer	Rocky Mountain Fabrication	*Operator ID*	
Model		*Serial Number*	T-7290
Location Note			
Device Description	Cooing Water.		

4 Fixed Roof Storage Tanks (Table C-1)

5 Compressors (Table D)

5.1 Compressor

Device ID #	**101285**	*Device Name*	**Compressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	D-003
Model	2 PHE-2	*Serial Number*	K-3 (S/N EM-601, 602)
Location Note	A-03C		
Device Description	Engine Use: Vapor Recovery Rating: 65 bhp Rated Capacity: 675 scfm Driver Type: Electric Device Type HP Rating: 125 Emission Control: Housing/seals to vapor recovery		

5.2 Tank Vapor Recovery Compressor

Device ID #	**101286**	*Device Name*	**Tank Vapor Recovery Compressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	D-004
Model	2 PHE-2	*Serial Number*	K-3A (S/N EM-633, 634)
Location Note	A-03C		
Device Description	Engine Use: Vapor Recovery Rating: 65 bhp Rated Capacity: 675 scfm Driver Type: Electric Device Type HP Rating: 125 Device Grouping No: F-30016-13 Emission Control: Housing/seals to vapor recovery		

5.3 SCR Combustion Air Blower

Device ID #	**101287**	*Device Name*	**SCR Combustion Air Blower**
Rated Heat Input		*Physical Size*	
Manufacturer	Illinois	*Operator ID*	D-006
Model	40RHB42-5	*Serial Number*	K-520A (S/N 3519)
Location Note	A-10B		
Device Description	Engine Use: SCR Combustion Air Blower Rating:unknown Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: 40 Device Grouping No: D-1006006-10		

5.4 SCR Combustion Air Blower

Device ID #	**101288**	*Device Name*	**SCR Combustion Air Blower**
Rated Heat Input		*Physical Size*	
Manufacturer	Illinois	*Operator ID*	D-007
Model	40RHB42-5	*Serial Number*	K520B (S/N 3520
Location Note	A-10B		
Device Description	Engine Use: SCR Combustion Air Blower Rating:unknown Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: 40 Device Grouping No: D-1006006-10		

6 Pumps (Table E)

6.1 Recycle Oil Pump

Device ID #	**101296**	*Device Name*	**Recycle Oil Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-041
Model	GTS-L-168	*Serial Number*	P-5A S/N 49888
Location Note	A-03B		
Device Description	Service: Recycle Oil Fluid Pumped: Oil Rated Capacity: 630 gpm Driver Type: Electric Device Type HP Rating: 250 Device Grouping No: F-30011-24		

6.2 Recycle Oil Pump

Device ID #	**101297**	*Device Name*	**Recycle Oil Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-042
Model	GTS-L-168	*Serial Number*	P-5B S/N 49887
Location Note	A-03B		
Device Description	Service: Recycle Oil Fluid Pumped: Oil Rated Capacity: 630 gpm Driver Type: Electric Device Type HP Rating: 250 Device Grouping No: F-30011-24		

6.3 Reject Water Disposal Pump

Device ID #	**101298**	***Device Name***	**Reject Water Disposal Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Worthington	*Operator ID*	E-043
Model	6HQ1558	*Serial Number*	P-6A S/N 56-910681
Location Note	A-04		
Device Description	Service: Recycle Oil Fluid Pumped: Reject H2O Rated Capacity: 750 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: F-40001-21		

6.4 Reject Water Disposal Pump

Device ID #	**101299**	***Device Name***	**Reject Water Disposal Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Durco	*Operator ID*	E-044
Model		*Serial Number*	P-6B S/N 318725
Location Note	A-04		
Device Description	Service: Recycle Oil Fluid Pumped: Reject H2O Rated Capacity: 550 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: F-40001-21		

6.5 Reject Water Disposal Pump

Device ID #	**101300**	*Device Name*	**Reject Water Disposal Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Durco	*Operator ID*	E-045
Model		*Serial Number*	P-6C S/N 318726
Location Note	A-04		
Device Description	Service: Reject H2O Discharge Pump Fluid Pumped: Reject H2O Rated Capacity: 550 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: F-40001-21		

6.6 Relief Knock-out SGL Pump

Device ID #	**101301**	*Device Name*	**Relief Knock-out SGL Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Worthington	*Operator ID*	E-057
Model	8HQ155 B	*Serial Number*	P-25A S/N 56-10685
Location Note	A-03B		
Device Description	Serial No: P-25A S/N 56-10685 Service: Relief Drain Fluid Pumped: Crude Condensate Rated Capacity: 3650 gpm Driver Type: Electric Device Type HP Rating:200 Device Grouping No: F-30013-14		

6.7 Relief Knock-out SGL Pump

Device ID #	**101302**	***Device Name***	**Relief Knock-out SGL Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Worthington	*Operator ID*	E-058
Model	8HQ155 B	*Serial Number*	P-25B S/N 56-10685A
Location Note	A-03B		
Device Description	Service: Relief Drain Fluid Pumped: Crude Condensate Rated Capacity: 3650 gpm Driver Type: Electric Device Type HP Rating:200 Device Grouping No: F-30013-14		

6.8 Oil Water Drain Pump

Device ID #	**101303**	***Device Name***	**Oil Water Drain Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-072
Model	GTS-074	*Serial Number*	P-50A S/N 028343-1
Location Note	A-09		
Device Description	Service: Oily Water Transfer Fluid Pumped: Oily Water Rated Capacity: 98 gpm Driver Type: Electric Device Type HP Rating:25 Device Grouping No: F-10045-15		

6.9 Oil Water Drain Pump

Device ID #	**101304**	***Device Name***	**Oil Water Drain Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-073
Model	GTS-074	*Serial Number*	P-50B S/N 028343-2
Location Note	A-09		
Device Description	Service: Oily Water Transfer Fluid Pumped: Oily Water Rated Capacity: 98 gpm Driver Type: Electric Device Type HP Rating:25 Device Grouping No: F-10045-15		

6.10 Charge Pump

Device ID #	**101305**	***Device Name***	**Charge Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Byron Jackson	*Operator ID*	E-074
Model	DVS	*Serial Number*	P-601A S/N 841-S-0043
Location Note	A-03B		
Device Description	Service: Crude Oil Shipping Fluid Pumped: Crude Oil Rated Capacity: 3275 gpm Driver Type: Electric Device Type HP Rating:300 Device Grouping No: D-60003-8		

6.11 Charge Pump

Device ID #	**101306**	***Device Name***	**Charge Pump**
Rated Heat Input		*Physical Size*	
Manufacturer	Byron Jackson	*Operator ID*	E-075
Model	DVS	*Serial Number*	P-601B S/N 841-S-0044
Location Note	A-03B		
Device Description	Service: Crude Oil Shipping Fluid Pumped: Crude Oil Rated Capacity: 3275 gpm		

Driver Type: Electric
Device Type HP Rating:300
Device Grouping No: D-60003-8

6.12 Flare Knockout Drum

Device ID #	**101307**	*Device Name*	**Flare Knockout Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	E-156
Model	A	*Serial Number*	P-7120A S/N 068553
Location Note	G-71		
Device Description	Service: Flare Condensate Fluid Pumped: Hydrocarbon Condensate Rated Capacity: 150 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: 71-ESB-7071-3 Emission Control: Dual seals utilized		

6.13 Flare Knockout Drum

Device ID #	**101308**	*Device Name*	**Flare Knockout Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	E-157
Model	A	*Serial Number*	P-7120B S/N 068554
Location Note	G-71		
Device Description	Service: Flare Condensate Fluid Pumped: Hydrocarbon Condensate Rated Capacity: 150 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: 71-ESB-7071-3 Emission Control: Dual seals utilized		

6.14 Flare Knockout Drum

Device ID #	**101309**	*Device Name*	**Flare Knockout Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	E-158
Model	A	*Serial Number*	P-7120C S/N 068555
Location Note	G-71		
Device Description	Service: Flare Condensate Fluid Pumped: Hydrocarbon Condensate Rated Capacity: 150 gpm Driver Type: Electric Device Type HP Rating:15 Device Grouping No: 71-ESB-7071-3 Emission Control: Dual seals utilized		

6.15 Submersible Drainage Pump

Device ID #	**101310**	*Device Name*	**Submersible Drainage Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-162
Model		*Serial Number*	P-26
Location Note	Oil Plant Utilities		
Device Description	Service: Sump Fluid Pumped: Waste Oil Rated Capacity: unknown Driver Type: Electric Device Type HP Rating:unknown Device Grouping No: F-10045-15		

6.16 Emergency Containment Basin Pump

Device ID #	**101311**	*Device Name*	**Emergency Containment Basin Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-163
Model		*Serial Number*	P-S7
Location Note	4		
Device Description	Service: Sump Fluid Pumped: Oil Rated Capacity: 100 gpm Driver Type: Electric Device Type HP Rating:3 Device Grouping No: F-40001-21		

6.17 Impound Basin Sump Pump

Device ID #	**101312**	*Device Name*	**Impound Basin Sump Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-164
Model		*Serial Number*	P-S8
Location Note	3		
Device Description	Service: Sump Fluid Pumped: Oil Rated Capacity: 100 gpm Driver Type: Electric Device Type HP Rating:3 Device Grouping No: F-30010-16		

6.18 Produced Water Injection Pump

Device ID #	**101321**	*Device Name*	**Produced Water Injection Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-176
Model		*Serial Number*	P-60A
Location Note	4		

Device Description	Service: Produced Water Disposal Fluid Pumped: Water Rated Capacity: 350 gpm Driver Type: Electric Device Type HP Rating: 900 Device Grouping No: D-40017-5

6.19 Produced Water Injection Pump

Device ID #	**101322**	***Device Name***	**Produced Water Injection Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-177
Model		*Serial Number*	P-60B
Location Note	4		
Device Description	Service: Produced Water Disposal Fluid Pumped: Water Rated Capacity: 350 gpm Driver Type: Electric Device Type HP Rating: 900 Device Grouping No: D-40017-5		

6.20 Produced Water Injection Pump

Device ID #	**101323**	***Device Name***	**Produced Water Injection Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-178
Model		*Serial Number*	P-61
Location Note	4		
Device Description	Service: Produced Water Disposal Fluid Pumped: Water Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: D-40017-5		

6.21 Submersible Drainage Pump

Device ID #	**107819**	***Device Name***	**Submersible Drainage Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-160
Model		*Serial Number*	P-26
Location Note			
Device Description	Electirc sump pump for waste oil.		

6.22 Emergency Containment Basin Pump

Device ID #	**107820**	***Device Name***	**Emergency Containment Basin Pump**
Rated Heat Input		*Physical Size*	3.00 gal/Minute
Manufacturer		*Operator ID*	E-161
Model		*Serial Number*	P-S5
Location Note			
Device Description	Electric pump in oil service.		

7 Pigging Equipment (Table F)

7.1 Pigging Equipment Receiver-oil

Device ID #	**101324**	***Device Name***	**Pigging Equipment Receiver-oil**
Rated Heat Input		*Physical Size*	
Manufacturer	Progressive Metals	*Operator ID*	F-001
Model	S/N 860711-1	*Serial Number*	L-202
Location Note	03		
Device Description	Equipment Type: Receiver Service: Oil/Crude Pig Unit dia x length (ft): 2.3 x 12 Attached Pipe dia x length (ft): 2.1 x 12 Operating Press (psig): 185		

Operating Temp (F): 68
Vapor mol wt (lb/lb-mol): 50
Pigging Events: 1/da; 60/yr
Emission Control: Vapor Recovery
Device Grouping No: D-20302-11

7.2 Pigging Equipment Receiver-gas

Device ID #	**101325**	***Device Name***	**Pigging Equipment Receiver-gas**
Rated Heat Input		*Physical Size*	
Manufacturer	Modco, Inc.	*Operator ID*	F-002
Model		*Serial Number*	L-502
Location Note	10-A		
Device Description	Equipment Type: Receiver Service: Sweet Gas Pig Unit dia x length (ft): 2.0 x 12 Attached Pipe dia x length (ft): 1.7 x 12 Operating Press (psig): 575 Operating Temp (F): 56 Vapor mol wt (lb/lb-mol): 21.65 Pigging Events: 1/da; 60/yr Emission Control: Vapor Recovery Device Grouping No: D-503-22-21		

8 Pressure Vessels (Table G)

8.1 NH4 Storage

Device ID #	**101326**	***Device Name***	**NH4 Storage**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	G-001
Model		*Serial Number*	V-525
Location Note	Plant 10		
Device Description	Equipment Type: Horizontal Service: Nox Control Unit dia x length (ft): 8 x 22 Operating Press (psig): 267 max Operating Temp (F): 450 max Emission Control: none Device Grouping No: C-106008-9		

8.2 Deaerator Flash Pot

Device ID #	**101327**	*Device Name*	**Deaerator Flash Pot**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	G-002
Model		*Serial Number*	V-61
Location Note	Plant 10		
Device Description	Manufacturer: unknown Model: unknown Equipment Type: Vertical Service: Amine Unit Device Grouping No: F-10039-21		

8.3 Polishing Filter

Device ID #	**101328**	*Device Name*	**Polishing Filter**
Rated Heat Input		*Physical Size*	
Manufacturer	Cuno, Inc.	*Operator ID*	G-043
Model		*Serial Number*	K-31A S/N 10536
Location Note	A-03B		
Device Description	Equipment Type: Filter Service: Produced Water Device Grouping No: D-40015-4		

8.4 Polishing Filter

Device ID #	**101329**	*Device Name*	**Polishing Filter**
Rated Heat Input		*Physical Size*	
Manufacturer	Cuno, Inc.	*Operator ID*	G-044
Model		*Serial Number*	K-31B S/N 10537
Location Note	A-03B		
Device Description	Equipment Type: Filter Service: Produced Water Device Grouping No: D-40015-4		

8.5 Freewater Knockout -Flow Splitter

Device ID #	**101330**	***Device Name***	**Freewater Knockout -Flow Splitter**
Rated Heat Input		*Physical Size*	
Manufacturer	Kaiser Steel	*Operator ID*	G-059
Model		*Serial Number*	V-1A S/N FP-1227
Location Note	A-03A		
Device Description	Equipment Type: Horizontal Service: Freewater Knockout Unit dia x length (ft): 13 x 90 Operating Press (psig): 160 Operating Temp (F): 170 Emission Control: Vapor recovery Device Grouping No: F 30002-15		

8.6 1st Stage Suction Scrubber

Device ID #	**101331**	***Device Name***	**1st Stage Suction Scrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-070
Model		*Serial Number*	V-17 S/N 84655-1
Location Note	A-03C		
Device Description	Equipment Type: Vertical Service: Compressor Inlet Scrubber Unit dia x length (ft): 1.2 x 6.2 Operating Press (psig): 1 Operating Temp (F): 70 Emission Control: none Device Grouping No: F-30012-18		

8.7 1st Stage Suction Scrubber

Device ID #	**101332**	***Device Name***	**1st Stage Suction Scrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-071
Model		*Serial Number*	V-17A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Vertical Service: Compressor Inlet Scrubber Unit dia x length (ft): 1.2 x 6.2 Operating Press (psig): 1 Operating Temp (F): 70 Emission Control: none Device Grouping No: F-3-0016-13		

8.8 Propane Storage Vessel

Device ID #	**101333**	***Device Name***	**Propane Storage Vessel**
Rated Heat Input		*Physical Size*	
Manufacturer	Riley Beard	*Operator ID*	G-075
Model		*Serial Number*	V-20D S/N 109182-01-4
Location Note	G-83B		
Device Description	Equipment Type: Horizontal Service: Liquid Propane Storage Unit dia x length (ft): 12.8 x 102.0 Operating Press (psig): 132 Operating Temp (F): 70 Emission Control: Vapor Recovery Device Grouping No: F-6050-22		

8.9 Propane Storage Vessel

Device ID #	**101334**	***Device Name***	**Propane Storage Vessel**
Rated Heat Input		*Physical Size*	
Manufacturer	Riley Beard	*Operator ID*	G-076
Model		*Serial Number*	V-20E S/N 109182-01-5
Location Note	G-73B		
Device Description	Equipment Type: Horizontal Service: Liquid Propane Storage Unit dia x length (ft): 12.8 x 102.0 Operating Press (psig): 132 Operating Temp (F): 70 Emission Control: Vapor Recovery Device Grouping No: F-6050-22		

8.10 Relief K-O Drum

Device ID #	**101335**	***Device Name***	**Relief K-O Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	Alameda Tank	*Operator ID*	G-083
Model		*Serial Number*	V-50 S/N 2817
Location Note	A-03A		
Device Description	Equipment Type: Horizontal Service: Knockout Unit dia x length (ft): 13.0 x 3.2 Operating Press (psig): 1 Operating Temp (F): 70 Emission Control: Vapor Recovery Device Grouping No: F-10036-25		

8.11 Vapor Recovery Knockout

Device ID #	**101336**	***Device Name***	**Vapor Recovery Knockout**
Rated Heat Input		*Physical Size*	
Manufacturer	Modular Prod., Inc.	*Operator ID*	G-084
Model		*Serial Number*	V-51 S/N 4953-V47
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: Condensate Knockout Unit dia x length (ft): 4.0 x 10.0 Operating Press (psig): 1 Operating Temp (F): 100 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.12 VRU K-O Liquid Blowcase

Device ID #	**101337**	***Device Name***	**VRU K-O Liquid Blowcase**
Rated Heat Input		*Physical Size*	
Manufacturer	Pro-Mag Ltd.	*Operator ID*	G-085
Model	PM80H-4S	*Serial Number*	V-52 S/N*
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: Condensate Blow Case Unit dia x length (ft): 0.7 x 2.0 Operating Press (psig): 100 Operating Temp (F): 100 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.13 1st Stage Suction Pulsation Suppressor

Device ID #	**101338**	***Device Name***	**1st Stage Suction Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-086
Model		*Serial Number*	V-56 S/N 84466-2
Location Note	G-73B		
Device Description	Equipment Type: Vertical Service: 2nd Stage Suction Scrubber Unit dia x length (ft): unknown Operating Press (psig): unknown Operating Temp (F): unknown Emission Control: na Device Grouping No: F-30012-18		

8.14 1st Stage Suction Pulsation Suppressor

Device ID #	**101339**	***Device Name***	**1st Stage Suction Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-087
Model		*Serial Number*	V-56 S/N 84485-3
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 1st Stage Suction Pulsation Unit dia x length (ft): 1.4 x 3.0 Operating Press (psig): 1 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.15 1st Stage Suction Pulsation Suppressor

Device ID #	**101340**	***Device Name***	**1st Stage Suction Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-088
Model		*Serial Number*	V-56A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 1st Stage Suction Pulsation Unit dia x length (ft): 1.4 x 2.5 Operating Press (psig): unknown Operating Temp (F): unknown Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.16 1st Stage Discharge Pulsation Suppressor

Device ID #	**101341**	***Device Name***	**1st Stage Discharge Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-089
Model		*Serial Number*	V-57 S/N 84465-4
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 1st Stage Discharge Pulsation Unit dia x length (ft): 1.3 x 2.5 Operating Press (psig): 20 Operating Temp (F): 195 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.17 1st Stage Discharge Pulsation Suppressor

Device ID #	**101342**	***Device Name***	**1st Stage Discharge Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-090
Model		*Serial Number*	V-57A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 1st Stage Discharge Pulsation Unit dia x length (ft): 1.3 x 2.5 Operating Press (psig): unknown Operating Temp (F): unknown Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.18 2nd Stage Suction Pulsation Suppressor

Device ID #	**101343**	***Device Name***	**2nd Stage Suction Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-091
Model		*Serial Number*	V-58 S/N 84465-5
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 2nd Stage Suction Pulsation Unit dia x length (ft): 1.1 x 1.5 Operating Press (psig): 20 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.19 2nd Stage Suction Pulsation Suppressor

Device ID #	**101344**	*Device Name*	**2nd Stage Suction Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-092
Model		*Serial Number*	V-58A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 2nd Stage Suction Pulsation Unit dia x length (ft): 1.1 x 1.5 Operating Press (psig): unknown Operating Temp (F): unknown Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.20 2nd Stage Discharge Pulsation Suppressor

Device ID #	**101345**	*Device Name*	**2nd Stage Discharge Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-093
Model		*Serial Number*	V-59 S/N 84465-8
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 2nd Stage Discharge Pulsation Unit dia x length (ft): 1.0 x 1.7 Operating Press (psig): 40 Operating Temp (F): 160 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.21 2nd Stage Discharge Pulsation Suppressor

Device ID #	**101346**	*Device Name*	**2nd Stage Discharge Pulsation Suppressor**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-094
Model		*Serial Number*	V-59A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Horizontal Service: 2nd Stage Discharge Pulsation Unit dia x length (ft): 1.0 x 1.7 Operating Press (psig): 40 Operating Temp (F): 160 Emission Control: Vapor Recovery Device Grouping No: F-30016-13		

8.22 2nd Stage Suction Scrubber

Device ID #	**101347**	*Device Name*	**2nd Stage Suction Scrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-095
Model		*Serial Number*	V-60 S/N 84465-2
Location Note	A-03C		
Device Description	Equipment Type: Vertical Service: Compressor Inlet Scrubber Unit dia x length (ft): 1.1 x 6.2 Operating Press (psig): 20 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: F-30012-18		

8.23 2nd Stage Suction Scrubber

Device ID #	**101348**	***Device Name***	**2nd Stage Suction Scrubber**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll-Rand	*Operator ID*	G-096
Model		*Serial Number*	V-60A S/N*
Location Note	A-03C		
Device Description	Equipment Type: Vertical Service: 2nd Stage Suction Pulsation Unit dia x length (ft): 1.1 x 6.2 Operating Press (psig): unknown Operating Temp (F): unknown Emission Control: Vapor Recovery Device Grouping No: F-30016-13		

8.24 Fuel Gas Knockout Pot

Device ID #	**101349**	***Device Name***	**Fuel Gas Knockout Pot**
Rated Heat Input		*Physical Size*	
Manufacturer	Eaton	*Operator ID*	G-097
Model		*Serial Number*	V-64A S/N N-8702
Location Note	A-10A		
Device Description	Equipment Type: Vertical Service: Fuel Gas Scrubber Knockout Unit dia x length (ft): 1.9 x 8.5 Operating Press (psig): 310 Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: F-30016-13		

8.25 Fuel Gas Knockout Pot

Device ID #	**101350**	***Device Name***	**Fuel Gas Knockout Pot**
Rated Heat Input		*Physical Size*	
Manufacturer	Eaton	*Operator ID*	G-098
Model		*Serial Number*	V-64B S/N N-8698

Location Note	A-10A
Device Description	Equipment Type: Vertical Service: Fuel Gas Scrubber Knockout Unit dia x length (ft): 1.9 x 8.5 Operating Press (psig): 310 Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: F-100006-12

8.26 Fuel Gas Knockout Pot

Device ID #	101351	*Device Name*	Fuel Gas Knockout Pot
Rated Heat Input		*Physical Size*	
Manufacturer	Eaton	*Operator ID*	G-099
Model		*Serial Number*	V-64C S/N 8799
Location Note	A-10A		
Device Description	Equipment Type: Vertical Service: Fuel Gas Scrubber Knockout Unit dia x length (ft): 1.9 x 8.5 Operating Press (psig): 310 Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: F-100007-12		

8.27 Fuel Gas Knockout Pot

Device ID #	101352	*Device Name*	Fuel Gas Knockout Pot
Rated Heat Input		*Physical Size*	
Manufacturer	Eaton	*Operator ID*	G-100
Model		*Serial Number*	V-64D S/N 8700
Location Note	A-10A		
Device Description	Equipment Type: Vertical Service: Fuel Gas Scrubber Knockout Unit dia x length (ft): 1.9 x 8.5 Operating Press (psig): 310 Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: F-100011-10		

8.28 Wet Oil Strainer

Device ID #	**101353**	*Device Name*	**Wet Oil Strainer**
Rated Heat Input		*Physical Size*	
Manufacturer	Arrow Engineer	*Operator ID*	G-102
Model		*Serial Number*	V-201A S/N V-84-454-A
Location Note	A-03		
Device Description	Equipment Type: Vertical Service: Wet Oil Strainer Unit dia x length (ft): 1.3 x 2.8 Operating Press (psig): 180 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: D-20304-10		

8.29 Wet Oil Strainer

Device ID #	**101354**	*Device Name*	**Wet Oil Strainer**
Rated Heat Input		*Physical Size*	
Manufacturer	Arrow Engineer	*Operator ID*	G-103
Model		*Serial Number*	V-201A S/N V-84-454-A
Location Note	A-03		
Device Description	Equipment Type: Vertical Service: Wet Oil Strainer Unit dia x length (ft): 1.3 x 2.8 Operating Press (psig): 180 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: D-20304-10		

8.30 Wet Oil Strainer

Device ID #	**101355**	*Device Name*	**Wet Oil Strainer**
Rated Heat Input		*Physical Size*	
Manufacturer	Arrow Engineer	*Operator ID*	G-104
Model		*Serial Number*	V-201C S/N V-84-

Location Note	A-03C
Device Description	Equipment Type: Vertical Service: Wet Oil Strainer Unit dia x length (ft): 1.3 x 2.8 Operating Press (psig): 180 Operating Temp (F): 80 Emission Control: Vapor Recovery Device Grouping No: D-20303-11

8.31 Intake Separator

Device ID #	**101356**	*Device Name*	**Intake Separator**
Rated Heat Input		*Physical Size*	
Manufacturer	General Welding	*Operator ID*	G-105
Model		*Serial Number*	V-1000 S/N 16809
Location Note	G-10A		
Device Description	Equipment Type: Vertical Service: Separator Unit dia x length (ft): 11.0 x 26.0 Operating Press (psig): 575 Operating Temp (F): 67 Emission Control: Vapor Recovery Device Grouping No: 10A-ESB-7010-10		

8.32 Flare Knockout Drum

Device ID #	**101357**	*Device Name*	**Flare Knockout Drum**
Rated Heat Input		*Physical Size*	
Manufacturer	McIver & Smith	*Operator ID*	G-179
Model		*Serial Number*	V-7120A S/N N-11745
Location Note	G-71		
Device Description	Equipment Type: Horizontal Service: Flare Knockout Unit dia x length (ft): 13.0 x 57.0 Operating Press (psig): atmospheric Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: 71-ESB-7070-8		

8.33 Flare Knockout Drum

Device ID #	101358	*Device Name*	Flare Knockout Drum
Rated Heat Input		*Physical Size*	
Manufacturer	McIver & Smith	*Operator ID*	G-181
Model		*Serial Number*	V-7120B S/N N-11746
Location Note	G-71		
Device Description	Equipment Type: Horizontal Service: Flare Knockout Unit dia x length (ft): 13.0 x 57.0 Operating Press (psig): atmospheric Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: 71-ESB-7070-8		

8.34 Liquid Blowdown Drum

Device ID #	101359	*Device Name*	Liquid Blowdown Drum
Rated Heat Input		*Physical Size*	
Manufacturer	McIver & Smith	*Operator ID*	G-182
Model		*Serial Number*	V-7130 S/N N-11747
Location Note	G-71		
Device Description	Equipment Type: Horizontal Service: Liquid Blowdown Unit dia x length (ft): 4.5 x15.0 Operating Press (psig): atmospheric Operating Temp (F): 60 Emission Control: Vapor Recovery Device Grouping No: 71-ESB-7071-3		

9 Heat Exchangers (Table H)

10 Flares and Thermal Oxidizers (Table J)

10.1 Flare

Device ID #	**000996**	***Device Name***	**Flare**
Rated Heat Input	18200.000 MMBtu/Hour	*Physical Size*	
Manufacturer	Peabody Engineering	*Operator ID*	J-001
Model		*Serial Number*	F-7120
Location Note	G-71		
Device Description	Flare Type: Steam Assisted Rating: 18,200 MMBtu/hr Flare gas HHV: 1200 Btu/scf Flare gas total S content: 160 - 239 ppmv as H2S Pilot/purge gas flow: 1200 scf/hr Pilot/purge gas HHV: 1100 Btu/scf Pilot/purge gas total S content: 4 ppmv as H2S Device SCC No: 3-06-009-99 Emission Control: Water Seal/Vapor Recovery		

11 Turbines (Table K)

11.1 Gas Turbine Generator (G-10A)

Device ID #	**000998**	***Device Name***	**Gas Turbine Generator (G-10A)**
Rated Heat Input	48.400 MMBtu/Hour	*Physical Size*	
Manufacturer	Allison	*Operator ID*	K-001
Model	KB-5	*Serial Number*	G-10A (S/N ASP-1060)
Location Note	A-10A		
Device Description	Equipment Use: Cogeneration Peak operating design rating: 3,695 kW Rating: 48.400 MMBtu/hr Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Single Shaft/Axial Flow Exhaust flow rate: 32,000 scfm Exhaust temp: 950 F Device Grouping No: F-100005-12 Device SCC No: 2-02-002-01 Max Operating Hrs: 8760/yr Emission Control: Water Injection/SCR		

11.2 Gas Turbine Generator (G-10B)

Device ID #	**000999**	***Device Name***	**Gas Turbine Generator (G-10B)**
Rated Heat Input	48.400 MMBtu/Hour	*Physical Size*	
Manufacturer	Allison	*Operator ID*	K-002
Model	KB-5	*Serial Number*	G-10B (S/N ASP-1083)
Location Note	A-10A		
Device Description	Equipment Use: Cogeneration Peak operating design rating: 3,695 kW Rating: 48.400 MMBtu/hr Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Single Shaft/Axial Flow Exhaust flow rate: 32,000 scfm Exhaust temp: 950 F Device Grouping No: F-100006-12 Device SCC No: 2-02-002-01 Max Operating Hrs: 8760/yr Emission Control: Water Injection/SCR		

11.3 Gas Turbine Generator (G-10C)

Device ID #	**001000**	***Device Name***	**Gas Turbine Generator (G-10C)**
Rated Heat Input	48.400 MMBtu/Hour	*Physical Size*	
Manufacturer	Allison	*Operator ID*	K-003
Model	KB-5	*Serial Number*	G-10C (S/N ASP-1082)
Location Note	A-10A		
Device Description	Equipment Use: Cogeneration Peak operating design rating: 3,695 kW Rating: 48.400 MMBtu/hr Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Single Shaft/Axial Flow Exhaust flow rate: 32,000 scfm Exhaust temp: 950 F Device Grouping No: F-100007-12 Device SCC No: 2-02-002-01 Max Operating Hrs: 8760/yr Emission Control: Water Injection/SCR		

11.4 Gas Turbine Generator (G-10D)

Device ID #	**001001**	***Device Name***	**Gas Turbine Generator (G-10D)**
Rated Heat Input	48.400 MMBtu/Hour	*Physical Size*	
Manufacturer	Allison	*Operator ID*	K-004
Model	KB-5	*Serial Number*	G-10D (S/N ASP-1059)
Location Note	A-10A		
Device Description	Equipment Use: Cogeneration Peak operating design rating: 3,695 kW Rating: 48.400 MMBtu/hr Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Single Shaft/Axial Flow Exhaust flow rate: 32,000 scfm Exhaust temp: 950 F Device Grouping No: F-100011-10 Device SCC No: 2-02-002-01 Max Operating Hrs: 8760/yr Emission Control: Water Injection/SCR		

11.5 Gas Turbine Generator (G-10E)

Device ID #	**001002**	***Device Name***	**Gas Turbine Generator (G-10E)**
Rated Heat Input	48.400 MMBtu/Hour	*Physical Size*	
Manufacturer	Allison	*Operator ID*	K-005
Model	KB-5	*Serial Number*	G-10E (S/N ASP-1084)
Location Note	A-10A		
Device Description	Equipment Use: Cogeneration Peak operating design rating: 3,695 kW Rating: 48.400 MMBtu/hr Fuel: NG w/ HHV 1100 Btu/scf; 4 ppmv as H2S Equipment Type: Single Shaft/Axial Flow Exhaust flow rate: 32,000 scfm Exhaust temp: 950 F Device Grouping No: F-100012-10 Device SCC No: 2-02-002-01 Max Operating Hrs: 8760/yr Emission Control: Water Injection/SCR		

12 Fugitive Hydrocarbon Components - CLP

12.1 FHC - Oil/Emulsion Service

12.1.1 Valves - controlled

Device ID #	**001007**	***Device Name***	**Valves - controlled**
Rated Heat Input		*Physical Size*	596.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.1.2 Valves - unsafe to monitor

Device ID #	**001025**	***Device Name***	**Valves - unsafe to monitor**
Rated Heat Input		*Physical Size*	15.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.1.3 Connection - controlled

Device ID #	**001011**	***Device Name***	**Connection - controlled**
Rated Heat Input		*Physical Size*	2648.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.1.4 Connection - unsafe to monitor

Device ID #	**005681**	***Device Name***	**Connection - unsafe to monitor**
Rated Heat Input		*Physical Size*	60.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.1.5 Seals - controlled

Device ID #	**008775**	***Device Name***	**Seals - controlled**
Rated Heat Input		*Physical Size*	6.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.1.6 PRVs - controlled

Device ID #	**001015**	***Device Name***	**PRVs - controlled**
Rated Heat Input		*Physical Size*	5.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2 FHC - Gas/Light Liquid Service

12.2.1 Valves - controlled

Device ID #	**001008**	***Device Name***	**Valves - controlled**
Rated Heat Input		*Physical Size*	1088.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.2 Valves - unsafe to monitor

Device ID #	**001026**	***Device Name***	**Valves - unsafe to monitor**
Rated Heat Input		*Physical Size*	20.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.3 Valves - NDE

Device ID #	**101397**	***Device Name***	**Valves - NDE**
Rated Heat Input		*Physical Size*	295.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.4 Connection - controlled

Device ID #	**001012**	***Device Name***	**Connection - controlled**
Rated Heat Input		*Physical Size*	4672.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.5 Connection - unsafe to monitor

Device ID #	**005682**	***Device Name***	**Connection - unsafe to monitor**
Rated Heat Input		*Physical Size*	84.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.6 Connection - NDE

Device ID #	**101398**	***Device Name***	**Connection - NDE**
Rated Heat Input		*Physical Size*	1140.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.7 Seals - controlled

Device ID #	**101399**	***Device Name***	**Seals - controlled**
Rated Heat Input		*Physical Size*	0.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.8 Seals - dual

Device ID #	**008776**	***Device Name***	**Seals - dual**
Rated Heat Input		*Physical Size*	7.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.9 PRVs - controlled

Device ID #	**001016**	***Device Name***	**PRVs - controlled**
Rated Heat Input		*Physical Size*	3.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.10 PRVs - unsafe to monitor

Device ID #	**101396**	***Device Name***	**PRVs - unsafe to monitor**

Rated Heat Input		*Physical Size*	0.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

2.2.11 PRVs - routed to flare

Device ID #	**101400**	***Device Name***	**PRVs - routed to flare**
Rated Heat Input		*Physical Size*	16.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

12.2.12 PRVs - tanks

Device ID #	**005683**	***Device Name***	**PRVs - tanks**
Rated Heat Input		*Physical Size*	8.00 Component Leakpath
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note			
Device Description			

13 Sumps and Wastewater Tanks (Table N)

13.1 Dirty Water Tank (T-4)

Device ID #	**008262**	***Device Name***	**Dirty Water Tank (T-4)**
Rated Heat Input		*Physical Size*	1174.00 Square Feet

			Area
Manufacturer	San Luis Tank	*Operator ID*	N-001
Model		*Serial Number*	T-4 (S/N 2621)
Location Note	A-04		
Device Description	Service: Waste Water Vessel Class: Secondary Emission Control: Covered; vapor recovery (99.5% eff longterm) Device Grouping No: F-40001-21		

13.2 Oily Water Drain Tank (T-25)

Device ID #	**008264**	***Device Name***	**Oily Water Drain Tank (T-25)**
Rated Heat Input		*Physical Size*	908.00 Square Feet Area
Manufacturer	San Luis Tank	*Operator ID*	N-008
Model		*Serial Number*	T-25 (S/N 2625)
Location Note	A-09		
Device Description	Service: Waste Oil & Water Vessel Class: Secondary Emission Control: Covered; vapor recovery (99.5% eff longterm) Device Grouping No: F-10045-15		

13.3 Emergency Containment Basin

Device ID #	**101401**	***Device Name***	**Emergency Containment Basin**
Rated Heat Input		*Physical Size*	48.50 Square Feet Sump Area
Manufacturer		*Operator ID*	N-013
Model		*Serial Number*	S-7
Location Note			
Device Description	Service: Waste Water Vessel Class: Tertiary Emission Control: Covered Device Grouping No: F-40001-21		

13.4 Hypochloride Tank

Device ID #	**101402**	***Device Name***	**Hypochloride Tank**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	N-014
Model		*Serial Number*	T-314
Location Note	G-10		
Device Description	Service: Potable Water Chemical Emission Control: Covered Device Grouping No: D-106190-7		

14 Crew Boats (Table Q)

14.1 Main Engine - Controlled

Device ID #	**008769**	***Device Name***	**Main Engine - Controlled**
Rated Heat Input		*Physical Size*	816.00 Brake Horsepower
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	Pacific OCS		
Device Description	Number of trips: 8/yr Load factor: 0.85 Time in mode - idle: 0 hrs Time in mode - maneuver: 0 hrs Time in mode - cruise: 2 hrs Device grouping number: M/V Price Tide Device SCC number: 2-03-001-01 Emission Control: 4 degree injection timing retard, intercooling, turbocharged to 8.4 g/bhp-hr; GPS installed		

14.2 Auxillary Engine - Controlled

Device ID #	008770	*Maximum Rated BHP*	168.00
Device Name	Auxillary Engine - Controlled	*Serial Number*	
Engine Use	Pumping Flood Water	*EPA Engine Family Name*	

Manufacturer		*Operator ID*	
Model Year	2002	*Fuel Type*	
Model			
DRP/ISC?	No	*Healthcare Facility?*	No
Daily Hours		*Annual Hours*	
Location Note	Pacific OCS		
Device Description	Number of trips: 8/yr Device grouping number: M/V Price Tide Device SCC number: 2-03-001-01 Emission Control: 4 degree injection timing retard, intercooling, turbocharged to 8.4 g/bhp-hr; GPS installed		

15 Solvent Activities (Table S)

15.1 General Solvent Usage

Device ID #	**005867**	***Device Name***	**General Solvent Usage**
Rated Heat Input		*Physical Size*	650.00 Gallons Solvent Used
Manufacturer		*Operator ID*	S-001
Model		*Serial Number*	
Location Note	Facility-wide		
Device Description	Coating/solvent brand name: Solvent Application: General usage Annual usage: 650 gal/yr Device SCC number: 4-02-001-01		

16 Stack Data (Table T)

16.1 Turbine Diverter Stack G-10B

Device ID #	**101406**	***Device Name***	**Turbine Diverter Stack G-10B**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	K-002
Model		*Serial Number*	
Location Note	A-10A		
Device	Stack hgt x dia: 12 ft x 10 in		

Description	Exhaust gas flow: 32,000 dscfm Exhaust gas temp: 950F Exhaust gas velocity: 0.2 ft/min

16.2 Turbine Diverter Stack G-10C

Device ID #	**101407**	***Device Name***	**Turbine Diverter Stack G-10C**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	K-003
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 12 ft x 10 in Exhaust gas flow: 32,000 dscfm Exhaust gas temp: 950F Exhaust gas velocity: 0.2 ft/min		

16.3 Turbine Diverter Stack G-10A

Device ID #	**101405**	***Device Name***	**Turbine Diverter Stack G-10A**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	K-001
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 12 ft x 10 in Exhaust gas flow: 32,000 dscfm Exhaust gas temp: 950F Exhaust gas velocity: 0.2 ft/min		

16.4 Turbine Diverter Stack G-10D

Device ID #	**101408**	***Device Name***	**Turbine Diverter Stack G-10D**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	K-004
Model		*Serial Number*	
Location Note	A-10A		

Device Description	Stack hgt x dia: 12 ft x 10 in Exhaust gas flow: 32,000 dscfm Exhaust gas temp: 950F Exhaust gas velocity: 0.2 ft/min		

16.5 Turbine Diverter Stack G-10E

Device ID #	**101409**	***Device Name***	**Turbine Diverter Stack G-10E**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	K-005
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 12 ft x 10 in Exhaust gas flow: 32,000 dscfm Exhaust gas temp: 950F Exhaust gas velocity: 0.2 ft/min		

16.6 SCR Stack

Device ID #	**101410**	***Device Name***	**SCR Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 45 ft x 8 in		

16.7 Flare

Device ID #	**101411**	***Device Name***	**Flare**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	J-001
Model		*Serial Number*	F-7120
Location Note	G-71		
Device Description	Stack hgt x dia: 165 ft x 48 in		

16.8 Starter A Cogen Stack

Device ID #	**101412**	***Device Name***	**Starter A Cogen Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 15 ft x 3 in		

16.9 Starter B Cogen Stack

Device ID #	**101413**	***Device Name***	**Starter B Cogen Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 15 ft x 3 in		

16.10 Starter C Cogen Stack

Device ID #	**101414**	***Device Name***	**Starter C Cogen Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 15 ft x 3 in		

16.11 Starter D Cogen Stack

Device ID #	**101415**	***Device Name***	**Starter D Cogen**

			Stack
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 15 ft x 3 in		

16.12 Starter E Cogen Stack

Device ID #	**101416**	*Device Name*	**Starter E Cogen Stack**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	A-10A		
Device Description	Stack hgt x dia: 15 ft x 3 in		

16.13 Supply Boat

Device ID #	**101417**	*Device Name*	**Supply Boat**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	Pacific OCS		
Device Description	Stack hgt x dia: 15 ft x 1 in Exhaust gas flow: 18,350 dscfm Exhaust gas temp: 500F		

16.14 Crew Boat

Device ID #	**101418**	*Device Name*	**Crew Boat**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	Pacific OCS		

Device Description	Stack hgt x dia: 1.5 ft x 1 in Exhaust gas flow: 3870 dscfm Exhaust gas temp: 600F

16.15 Flare Tip

Device ID #	**101419**	***Device Name***	**Flare Tip**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Location Note	Platform Hermosa		
Device Description	Stack hgt x dia: 120 ft x 1.4 in		

B EXEMPT EQUIPMENT

1 Emergency Firewater Pump

Device ID #	**000992**	***Device Name***	**Emergency Firewater Pump**
Rated Heat Input		*Physical Size*	267.00 Brake Horsepower
Manufacturer	Caterpillar	*Operator ID*	A-006
Model	3306D1	*Serial Number*	64Z03820
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note			
Device Description	Engine Use: Fire Water Pump Rating @ 2100 rpm Fuel: Diesel w/ HHV 19,620 Btu/lb; 0.05% wt S Engine Type: Lean/Non-Cyclic Device Grouping No: unknown Device SCC No: 2-02-001-02 Max Operating Hrs:24/da;200/qtr;200/yr		

2 Diesel Fuel Tank

Device ID #	**101284**	***Device Name***	**Diesel Fuel Tank**
Rated Heat Input		*Physical Size*	250.00 Gallons

Manufacturer	San Luis Tank	*Operator ID*	C-018
Model		*Serial Number*	T-40
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-08		
Device Description	Fquipment Type: Vertical Device Grouping No: F-10040-16 Device SCC No: unknown Max Operating Hrs: 8760/yr		

3 Compressor K1010 Lube Oil

Device ID #	101290	*Device Name*	Compressor K1010 Lube Oil
Rated Heat Input		*Physical Size*	39.00 gal/Minute
Manufacturer	Transamerican	*Operator ID*	E-002
Model	GG3DRS-187	*Serial Number*	K1010B P1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-10B		
Device Description	Service: Aux Lube Oil Fluid Pumped: Oil Driver Type: Electric Device Type HP Rating: 10 Device Grouping No: WB-ESB-7010-4		

4 Compressor K1010 Lube Oil

Device ID #	101289	*Device Name*	Compressor K1010 Lube Oil
Rated Heat Input		*Physical Size*	
Manufacturer	Transamerican	*Operator ID*	E-001
Model	GG3DRS-187	*Serial Number*	K-1010A P1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-10B		
Device Description	Service: Aux Lube Oil Fluid Pumped: Oil Rated Capacity: 39 gpm Driver Type: Electric Device Type HP Rating: 10 Device Grouping No: WB-ESB-7010-4		

5 Compressor K1230 Lube Oil

Device ID #	**101291**	***Device Name***	**Compressor K1230 Lube Oil**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-009
Model		*Serial Number*	K-1230A P2
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Service: Aux Lube Oil Fluid Pumped: Oil Rated Capacity: 39 gpm Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: WB-ESB-7032-4		

6 Compressor K1230 Lube Oil

Device ID #	**101292**	***Device Name***	**Compressor K1230 Lube Oil**
Rated Heat Input		*Physical Size*	39.00 gal/Minute
Manufacturer	Delaval	*Operator ID*	E-010
Model		*Serial Number*	K-1230B P2
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Service: Aux Lube Oil Fluid Pumped: Oil Rated Capacity: 39 gpm Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: WB-ESB-7032-4		

7 Compressor K1240 Lube Oil

Device ID #	**101293**	***Device Name***	**Compressor K1240 Lube Oil**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-013
Model		*Serial Number*	K-1240A P2
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Service: Aux Frame Oil Fluid Pumped: Oil Rated Capacity: 125 gpm Driver Type: Electric Device Type HP Rating: 25 Device Grouping No: WB-ESB-7037-5		

8 Compressor K1240 Lube Oil

Device ID #	**101294**	***Device Name***	**Compressor K1240 Lube Oil**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval	*Operator ID*	E-014
Model		*Serial Number*	K-1240B P1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Service: Aux Frame Oil Fluid Pumped: Oil Rated Capacity: 125 gpm Driver Type: Electric Device Type HP Rating: 25 Device Grouping No: WB-ESB-7037-5		

9 Compressor Lube Oil

Device ID #	101295	*Device Name*	**Compressor Lube Oil**
Rated Heat Input		*Physical Size*	
Manufacturer	Delaval (Common)	*Operator ID*	E-019
Model		*Serial Number*	K-1300 P1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-13		
Device Description	Service: Aux Frame Oil Fluid Pumped: Oil Rated Capacity: 125 gpm Driver Type: Electric Device Type HP Rating: 25 Device Grouping No: WB-ESB-7030A-6		

10 Condensate Pump

Device ID #	101313	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-165
Model		*Serial Number*	P-46A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30004-15		

11 Condensate Pump

Device ID #	**101314**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-166
Model		*Serial Number*	P-46B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30005-14		

12 Condensate Pump

Device ID #	**101315**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-167
Model		*Serial Number*	P-46C
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30006-14		

13 Condensate Pump

Device ID #	**101316**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-168
Model		*Serial Number*	P-47A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30004-15		

14 Condensate Pump

Device ID #	**101317**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-169
Model		*Serial Number*	P-47B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30005-14		

15 Condensate Pump

Device ID #	**101318**	*Device Name*	**Condensate Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-170
Model		*Serial Number*	P-47C
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	3		
Device Description	Service: Condensate Fluid Pumped: Condensate Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-30006-14		

16 Sewage Discharge Pump

Device ID #	**101319**	*Device Name*	**Sewage Discharge Pump**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-171
Model		*Serial Number*	P-19
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	4		
Device Description	Service: Sewage Fluid Pumped: Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-40001-21		

17 Sewage Discharge Pump

Device ID #	**101320**	*Device Name*	**Sewage Discharge Pump**
Rated Heat		*Physical Size*	

Input			
Manufacturer		*Operator ID*	E-172
Model		*Serial Number*	P-19A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	4		
Device Description	Service: Sewage Fluid Pumped: Rated Capacity: unknown Driver Type: Electric Device Type HP Rating: unknown Device Grouping No: F-40001-21		

18 Exchanger

Device ID #	**101361**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Bos-Hatten	*Operator ID*	H-002
Model		*Serial Number*	E1-K1010B S/N 85-2418B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-10B		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 10B-ESB-7016-4		

19 Exchanger

Device ID #	**101362**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Bos-Hatten	*Operator ID*	H-003
Model		*Serial Number*	E1-K1240A S/N 85-2419A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 12-ESB-7030A-6		

20 Exchanger

Device ID #	**101360**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Bos-Hatten	*Operator ID*	H-001
Model		*Serial Number*	E1-K1010A S/N 85-2418A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-10B		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 10B-ESB-7016-4		

21 Exchanger

Device ID #	**101363**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Bos-Hatten	*Operator ID*	H-004
Model		*Serial Number*	E1-K1240B S/N 85-2419B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 12-ESB-7030A-6		

22 Exchanger

Device ID #	**101364**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Bos-Hatten	*Operator ID*	H-005

Model		*Serial Number*	E1-K1300A (common)
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-13		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 12-ESB-7030A-6		

23 Exchanger

Device ID #	**101365**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	H-006
Model		*Serial Number*	E1-K1300B (common)
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-13		
Device Description	Equipment Type: Plate Service: Lube Oil Cooler Heat Medium: Water Device Grouping No: 12-ESB-7030A-6		

24 Oil/Oil Exchanger

Device ID #	**101366**	***Device Name***	**Oil/Oil Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	H-008
Model	UX-416-UP-420	*Serial Number*	E-1B S/N P-31211-H
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03B		
Device Description	Equipment Type: Plate and Frame Service: Oil Exchanger Heat Medium: Oil Device Grouping No: F-30005-14		

25 Oil/Water Exchanger

Device ID #	**101367**	***Device Name***	**Oil/Water Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Tranter	*Operator ID*	H-014
Model	UX-426-UP-400	*Serial Number*	E-2B S/N P-31217-H
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03B		
Device Description	Equipment Type: Plate and Frame Service: Oil Exchanger Heat Medium: Oil Device Grouping No: F-30005-14		

26 Interstage Cooler

Device ID #	**101368**	***Device Name***	**Interstage Cooler**
Rated Heat Input		*Physical Size*	
Manufacturer	Air Cooled Exch	*Operator ID*	H-026
Model	C 42 AM	*Serial Number*	E-17-1 S/N 840478-1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03B		
Device Description	Equipment Type: Fin-Fan Service: Interstage / Recycle Coole Heat Medium: Vapor Device Grouping No: F-30012-18		

27 Recycle Cooler

Device ID #	**101369**	***Device Name***	**Recycle Cooler**
Rated Heat Input		*Physical Size*	
Manufacturer	Air Cooled Exch	*Operator ID*	H-027
Model	C 42 AM	*Serial Number*	E-17-2 S/N 840478-2
Part 70 Insig?	No	*APCD Rule Exemption:*	

Location Note	A-03B
Device Description	Equipment Type: Fin-Fan Service: Interstage / Recycle Cooler Heat Medium: Vapor Device Grouping No: F-30012-18

28 Interstage Cooler

Device ID #	**101370**	***Device Name***	**Interstage Cooler**
Rated Heat Input		*Physical Size*	
Manufacturer	Air Cooled Exch	*Operator ID*	H-028
Model	C 42 AM	*Serial Number*	E-17A-1 S/N 85632-1
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03		
Device Description	Equipment Type: Fin-Fan Service: Interstage / Recycle Cooler Heat Medium: Vapor Device Grouping No: F-30016-13		

29 Recycle Cooler

Device ID #	**101371**	***Device Name***	**Recycle Cooler**
Rated Heat Input		*Physical Size*	
Manufacturer	Air Cooled Exch	*Operator ID*	H-029
Model	C 42 AM	*Serial Number*	E-17A-2 S/N 85632-2
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03B		
Device Description	Equipment Type: Fin-Fan Service: Interstage / Recycle Cooler Heat Medium: Vapor Device Grouping No: F-30016-13		

30 SCR Boiler-Direct Exchanger (exempt)

Device ID #	**101372**	***Device Name***	**SCR Boiler-Direct Exchanger (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Entec	*Operator ID*	H-030
Model	CH-2D1	*Serial Number*	E-503 S/N 85-511A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10B		
Device Description	Equipment Type: Shell/Tube Service: Exchanger Vaporator Heat Medium: Flame Device Grouping No: D-106007-4		

31 Condensor (exempt)

Device ID #	**101373**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-054
Model	E-1428T132	*Serial Number*	E-1245A / S/N R-1307-6A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

32 Condensor (exempt)

Device ID #	**101374**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-055
Model	4-1428T132	*Serial Number*	E-1245B / S/N R-1307-6B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

33 Condensor (exempt)

Device ID #	**101375**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-056
Model	4-1428T132	*Serial Number*	E-1245C S/N R-1307-6C
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	C Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-703A-6		

34 Condensor (exempt)

Device ID #	**101376**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-057
Model	E-1428T132	*Serial Number*	E-1245D / S/N R-1307-6D
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

35 Condensor (exempt)

Device ID #	**101377**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-058
Model	E-1428T132	*Serial Number*	E-1245E / S/N R-1307-6E
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7058-6		

36 Condensor (exempt)

Device ID #	**101378**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	

Manufacturer	Gearrainey	*Operator ID*	H-059
Model	E-1428T132	*Serial Number*	E-1245F / S/N R-1307-6F
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

37 Condensor (exempt)

Device ID #	**101379**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-060
Model	4-1428T132	*Serial Number*	E-1245G S/N R-1307-6G
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

38 Condensor (exempt)

Device ID #	**101380**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-061
Model	E-1428T132	*Serial Number*	E-1245H / S/N R-1307-6H
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-12		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 12-ESB-7038-6		

39 Condensor (exempt)

Device ID #	**101381**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-063
Model	1-1328T120	*Serial Number*	E-1310A / S/N R-1307-7A
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-13		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 13-ESB-7040-11		

40 Condensor (exempt)

Device ID #	**101382**	***Device Name***	**Condensor (exempt)**
Rated Heat Input		*Physical Size*	
Manufacturer	Gearrainey	*Operator ID*	H-064
Model	1-1328T120	*Serial Number*	E-1310B S/N R-1307-7B
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G-13		
Device Description	Equipment Type: Fin Fan Service: Steam Condenser Heat Medium: Refrigerant Device Grouping No: 13-ESB-7040-11		

41 Exchanger

Device ID #	**101383**	***Device Name***	**Exchanger**
Rated Heat Input		*Physical Size*	
Manufacturer	Ingersoll - Rand	*Operator ID*	H-109
Model		*Serial Number*	E-K-3 S/N *

Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-03C		
Device Description	Equipment Type: Fin Fan Service: Vapor recovery Heat Medium: Air Device Grouping No: unknown		

42 Exchanger (Oil Cooler)

Device ID #	**101384**	***Device Name***	**Exchanger (Oil Cooler)**
Rated Heat Input		*Physical Size*	
Manufacturer	Specialists Heat Exchanger Inc.	*Operator ID*	H-110
Model	M-21026-52	*Serial Number*	31529
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	G10E		
Device Description	Equipment Type: Fin Fan Service: cogen-oil Heat Medium: Air Device Grouping No: FP-5-013		

43 G10A Waste Heat Recovery Exchanger 1st Evaporator

Device ID #	**101385**	***Device Name***	**G10A Waste Heat Recovery Exchanger 1st Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer	Struthers	*Operator ID*	H-111
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10-A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

44 G10A Waste Heat Recovery Exchanger 2nd Evaporator

Device ID #	**101386**	***Device Name***	**G10A Waste Heat Recovery Exchanger 2nd Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	H-112
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10-A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

45 G10B Waste Heat Recovery Exchanger 1st Evaporator

Device ID #	**101387**	***Device Name***	**G10B Waste Heat Recovery Exchanger 1st Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

46 G10B Waste Heat Recovery Exchanger 2nd Evaporator

Device ID #	**101388**	***Device Name***	**G10B Waste Heat Recovery Exchanger 2nd Evaporator**

Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

47 G10C Waste Heat Recovery Exchanger 1st Evaporator

Device ID #	**101389**	***Device Name***	**G10C Waste Heat Recovery Exchanger 1st Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

48 G10C Waste Heat Recovery Exchanger 2nd Evaporator

Device ID #	**101390**	***Device Name***	**G10C Waste Heat Recovery Exchanger 2nd Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		

Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1

49 G10D Waste Heat Recovery Exchanger 1st Evaporator

Device ID #	**101391**	***Device Name***	**G10D Waste Heat Recovery Exchanger 1st Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

50 G10D Waste Heat Recovery Exchanger 2nd Evaporator

Device ID #	**101392**	***Device Name***	**G10D Waste Heat Recovery Exchanger 2nd Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

51 G10E Waste Heat Recovery Exchanger 1st Evaporator

Device ID #	**101393**	***Device Name***	**G10E Waste Heat Recovery Exchanger 1st Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

52 G10E Waste Heat Recovery Exchanger 2nd Evaporator

Device ID #	**101394**	***Device Name***	**G10E Waste Heat Recovery Exchanger 2nd Evaporator**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	
Model		*Serial Number*	
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	A-10A		
Device Description	Equipment Type: Tube Service: Waste Heat Recovery Heat Medium: Water Device Grouping No: WH-2105-1D1		

53 Economizer

Device ID #	**101395**	***Device Name***	**Economizer**
Rated Heat Input		*Physical Size*	
Manufacturer		*Operator ID*	E-504
Model		*Serial Number*	E 504
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	Plant 10		
Device Description	Equipment Type: Shell Tube Service: SCR Unit Heat Medium: Exhaust Device Grouping No: D-106007		

54 Clean Water Tank: (T-8)

Device ID #	**008263**	***Device Name***	**Clean Water Tank: (T-8)**
Rated Heat Input		*Physical Size*	1684.00 Square Feet Area
Manufacturer	San Luis Tank	*Operator ID*	N-030
Model		*Serial Number*	T-8
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	Oil Plant		
Device Description	Service: Clean Water Emission Control: Covered; vapor recovery (99.5% eff longterm)		

55 Fire Water

Device ID #	**101403**	***Device Name***	**Fire Water**
Rated Heat Input		*Physical Size*	81417.00 Square Feet Area
Manufacturer	San Luis Tank	*Operator ID*	N-031
Model		*Serial Number*	T-35
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	Gas Plant		

Device Description	Service: Fire Water Emission Control: Covered

56 Cooling Water

Device ID #	101404	*Device Name*	Cooling Water
Rated Heat Input		*Physical Size*	2262.00 Square Feet Area
Manufacturer	Rocky Mountain Fabrication	*Operator ID*	N-032
Model		*Serial Number*	T-7290 (S/N C-972)
Part 70 Insig?	No	*APCD Rule Exemption:*	
Location Note	Gas Plant		
Device Description	Service: Cooling Water Emission Control: Covered		

ATTACHMENT 10.4. Valves in Gas Service Subject to Monthly Monitoring

TO BE PROVIDED

ATTACHMENT 10.5. Helicopter Emission Tables

Point Arguello Project Helicopter Emissions Summary

Sykorski SK-76 Helicopters

Trip Segment	Climbout (min)	Approach (min)	Idle (min)	Cruise (min)	NOx (lbs/segment)	ROC (lbs/segment)	CO (lbs/segment)
SBA-Harvest	2	2	4	22	0.79	0.97	2.38
SBA-Hermosa	2	2	4	20	0.73	0.96	2.29
SBA-Hidalgo	2	2	4	25	0.88	0.97	2.51
SBA-Irene	2	2	4	25	0.88	0.97	2.51
Harvest-SBA	2	2	4	22	0.79	0.97	2.38
Hermosa-SBA	2	2	4	20	0.73	0.96	2.29
Hidalgo-SBA	2	2	4	25	0.88	0.97	2.51
Irene-SBA	2	2	4	25	0.88	0.97	2.51
SMA-Harvest	2	2	4	15	0.58	0.95	2.07
SMA-Hermosa	2	2	4	15	0.58	0.95	2.07
SMA-Hidalgo	2	2	4	15	0.58	0.95	2.07
SMA-Irene	2	2	4	10	0.43	0.95	1.86
Harvest-SMA	2	2	4	15	0.58	0.95	2.07
Hermosa-SMA	2	2	4	15	0.58	0.95	2.07
Hidalgo-SMA	2	2	4	15	0.58	0.95	2.07
Irene-SMA	2	2	4	10	0.43	0.95	1.86
Harvest-Harvest	2	2	4	0	0.13	0.93	1.42
Harvest-Hermosa	2	2	4	2	0.19	0.93	1.51
Harvest-Hidalgo	2	2	4	3	0.22	0.94	1.55
Harvest-Irene	2	2	4	5	0.28	0.94	1.64
Hermosa-Harvest	2	2	4	2	0.19	0.93	1.51
Hermosa-Hermosa	2	2	4	0	0.13	0.93	1.42
Hermosa-Hidalgo	2	2	4	3	0.22	0.94	1.55
Hermosa-Irene	2	2	4	5	0.28	0.94	1.64
Hidalgo-Harvest	2	2	4	3	0.22	0.94	1.55
Hidalgo-Hermosa	2	2	4	3	0.22	0.94	1.55
Hidalgo-Hidalgo	2	2	4	0	0.13	0.93	1.42
Hidalgo-Irene	2	2	4	5	0.28	0.94	1.64
Irene-Harvest	2	2	4	5	0.28	0.94	1.64
Irene-Hermosa	2	2	4	5	0.28	0.94	1.64
Irene-Hidalgo	2	2	4	5	0.28	0.94	1.64
Irene-Irene	2	2	4	5	0.28	0.94	1.64

Emission Factors

(lbs/hr)	Climbout	Approach	Idle	Cruise
NOx	2.60	1.00	0.10	1.80
THC	0.10	0.50	14.40	0.10
ROC (95% THC)	0.10	0.48	13.68	0.10
CO	2.10	5.40	17.60	2.60

ATTACHMENT 10.6. Arguello Comments on Draft Permit/APCD Response

TO Be Provided