DRAFT

PERMIT TO OPERATE 9105

and

PART 70 OPERATING PERMIT 9105

Platform Hidalgo

Parcel OCS P-0450
Point Arguello Oilfield
Outer Continental Shelf

EQUIPMENT OPERATOR

Plains Exploration and Production Co. (PXP)

OWNERSHIP

Arguello Inc.; Devon Energy Production Company LP; Sun Operating Limited Partnership; Whiting Petroleum Corporation; Koch Industries, Inc.; Harvest Energy, Inc.

Santa Barbara County
Air Pollution Control APCD

July 2008

TABLE OF CONTENTS

SECTION **PAGE**

1.0 INTRODUCTION 1

1.1 PURPOSE 1
1.2 FACILITY OVERVIEW 1
1.3 EMISSION SOURCES 4
1.4 EMISSION CONTROL OVERVIEW 5
1.5 OFFSETS/EMISSION REDUCTION CREDIT OVERVIEW 5
1.6 PART 70 OPERATING PERMIT OVERVIEW 5

2.0 PROCESS DESCRIPTION 7

2.1 PROCESS SUMMARY 7
2.2 SUPPORT SYSTEMS 11
2.3 DRILLING ACTIVITIES 12
2.4 MAINTENANCE/DEGREASING ACTIVITIES 12
2.5 PLANNED PROCESS TURNAROUNDS 12
2.6 OTHER PROCESSES 12
2.7 DETAILED PROCESS EQUIPMENT LISTING 12

3.0 REGULATORY REVIEW 12

3.1 RULE EXEMPTIONS CLAIMED 13
3.2 COMPLIANCE WITH APPLICABLE FEDERAL RULES AND REGULATIONS 14
3.3 COMPLIANCE WITH APPLICABLE STATE RULES AND REGULATIONS 15
3.4 COMPLIANCE WITH APPLICABLE LOCAL RULES AND REGULATIONS 16
3.5 COMPLIANCE HISTORY 20

4.0 ENGINEERING ANALYSIS 26

4.1 GENERAL 26
4.2 STATIONARY COMBUSTION SOURCES 26
4.4 CREW AND SUPPLY VESSELS 31
4.5 SULFUR TREATING/GAS SWEETENING UNIT 32
4.6 TANKS/VESSELS/SUMPS/SEPARATORS 32
4.7 VAPOR RECOVERY SYSTEMS 33
4.8 HELICOPTERS 33
4.9 OTHER EMISSION SOURCES 34
4.10 BACT/NSPS/NESHAP/MACT 35
4.11 CEMS/PROCESS MONITORING/CAM 35
4.12 SOURCE TESTING/SAMPLING 36

5.0 EMISSIONS 38

5.1 GENERAL 38
5.2 PERMITTED EMISSION LIMITS - EMISSION UNITS 38
5.3 PERMITTED EMISSION LIMITS - FACILITY TOTALS 39
5.4 PART 70: FEDERAL POTENTIAL TO EMIT FOR THE FACILITY 40
5.5 EXEMPT EMISSION SOURCES/PART 70 INSIGNIFICANT EMISSIONS 40
5.6 NET EMISSIONS INCREASE CALCULATION 40

6.0 AIR QUALITY IMPACT ANALYSES 53

6.1 MODELING 53
6.2 INCREMENTS 53
6.3 MONITORING 53

6.4 HEALTH RISK ASSESSMENT 53

7.0 CAP CONSISTENCY, OFFSET REQUIREMENTS AND ERCS 53

7.1 GENERAL 53
7.2 CLEAN AIR PLAN 54
7.3 OFFSET REQUIREMENTS 54
7.4 EMISSION REDUCTION CREDITS 55

8.0 LEAD AGENCY PERMIT CONSISTENCY 59

9.0 PERMIT CONDITIONS 59

9.A STANDARD ADMINISTRATIVE CONDITIONS 59
9.B. GENERIC CONDITIONS 64
9.C REQUIREMENTS AND EQUIPMENT SPECIFIC CONDITIONS 67
9.D APCD-ONLY CONDITIONS 101

LIST OF ATTACHMENTS

10.0 ATTACHMENTS

- 10.1 Emission Calculation Documentation
- 10.2 IDS Database Emission Tables
- 10.3 Equipment List
- 10.4 Valves in Gas Service Subject to Monthly Monitoring
- 10.5 Helicopter Emission Tables
- 10.6 PXP Comments on Draft Permit/APCD Response

LIST OF FIGURES and TABLES

TABLE/ FIGURE		PAGE
Figure 1.1	Location Map For Platform Hidalgo	2
Table 3.0-1	Variances Granted	4
Table 3.0-2	Notices Of Violation Issued	5
Table 3.1	Generic Federally-Enforceable APCD Rules	21
Table 3.2	Unit-Specific Federally-Enforceable APCD Rules	22
Table 3.3	Non-Federally-Enforceable APCD Rules	23
Table 3.4	Adoption Dates Of Apcd Rules Applicable At Issuance Of Permit	23
Table 4.1	Source Test Requirements	37
Table 5.0	Stationary Source NEI Since 1990	41
Table 5.1-1	Operating Equipment Description	41
Table 5.1-2	Equipment Emission Factors	43
Table 5.1-3	Emission Limits By Emission Unit – Short Term Limits	47
Table 5.1-4	Emission Limits By Emission Unit – Long Term Limits	47
Table 5.2	Total Permitted Facility Emissions	49
Table 5.3	Federal Potential To Emit	50
Table 5.4	Estimated Permit Exempt Emissions	51
Table 7.3-1	Rule 359 SOx Offsets	56
Table 7.3-2	Flare SOx Offsets	57
Table 7.4-1	ROC Emission Reduction Credits	58

ABBREVIATIONS/ACRONYMS

APCO	Air Pollution Control Officer
AP-42	USEPA *Compilation of Emission Factors* document
API	American Petroleum Institute
ASTM	American Society for Testing and Materials
ATC	Authority to Construct permit
BS&W	Basic sediment and water
bhp	brake horsepower
bpd	barrels per day (42 gallons per barrel)
BSFC	brake-specific fuel consumption
Btu	British thermal unit
CAAA	Clean Air Act Amendments of 1990
CAM	Compliance Assured Monitoring
CAP	Clean Air Plan
CARB	California Air Resources Board
CEMS	continuous emissions monitoring system
CFR	Code of Federal Regulations
clp	component-leak path
CO	carbon monoxide
CO_2	carbon dioxide
COA	corresponding offshore area
ERC	emission reduction credit
FHC	fugitive hydrocarbon
FR	Federal Register
gr	grain
g	gram
gal	gallon
GOHF	Gaviota Oil Heating Facility
HHV	higher heating value
H_2S	hydrogen sulfide
H&SC	California Health and Safety Code
IC	internal combustion
I&M	inspection and maintenance
k	thousand
kV	kilovolt
lb	pound
LHV	lower heating value
MACT	Maximum Achievable Control Technology
MCC	motor control center
MDEA	methyl diethanolamine
MM, mm	million
MMS	Minerals Management Service
MSDS	Material Safety Data Sheet
MW	molecular weight, Megawatts
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NGL	natural gas liquids
NO_x	oxides of nitrogen (calculated as NO_2)
NSPS	New Source Performance Standards

OCS	Outer Continental Shelf
PFD	process flow diagram
P&ID	piping and instrumentation diagram
PTO	Permit to Operate permit
PTO Mod	Permit to Operate Modification permit
ppmv	parts per million volume (concentration)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PM	particulate matter
PM_{10}	particulate matter less than 10 □m in size
PSV	pressure safety valve
PTE	potential to emit
PTO	Permit to Operate
PRD	pressure relief device
PVRV	pressure vacuum relief valve
ROC	reactive organic compounds
SBCAPCD	Santa Barbara County Air Pollution Control APCD or APCD or APCD
scf	standard cubic feet
scfd	standard cubic feet per day
scfm	standard cubic feet per minute
SCAQMD	South Coast Air Quality Management APCD
SO_x	sulfur oxides
TEG	triethylene glycol
TOC	total organic compounds
tpq	tons per quarter
tpy	tons per year
Trn O/O	transfer of owner/operator permit application
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency or EPA
UPS	uninterrupted power supply
VRS	vapor recovery system
wt %	weight percent

Blank Page

1.0 Introduction

1.1 Purpose

General: The Santa Barbara County Air Pollution Control APCD (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 nonattainment area for the state ozone and PM_{10} ambient air quality standards.

Part 70 Permitting: The issuance of this Part 70 permit to Platform Hidalgo satisfies the permit issuance requirements of the APCD's Part 70 operating permit program. 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.

Platform Hidalgo is a part of the *Point Arguello Project Stationary Source* (SSID = 1325), which is a major source for VOC[1], NO_x, CO, and SO_x. 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.

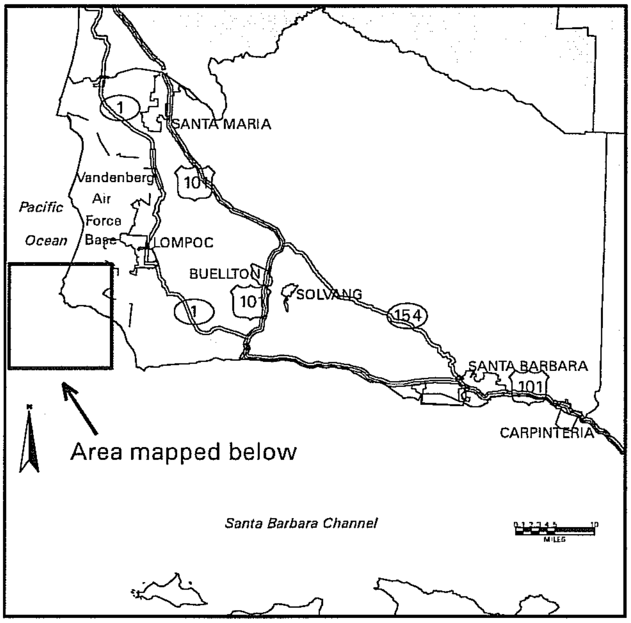
Pursuant to the stated aims of Title V of the CAAA of 1990 (i.e., the Part 70 operating permit program), this permit has been designed to meet two objectives. First, compliance with all conditions in this permit would ensure compliance with all federally-enforceable requirements for the facility. Second, 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.

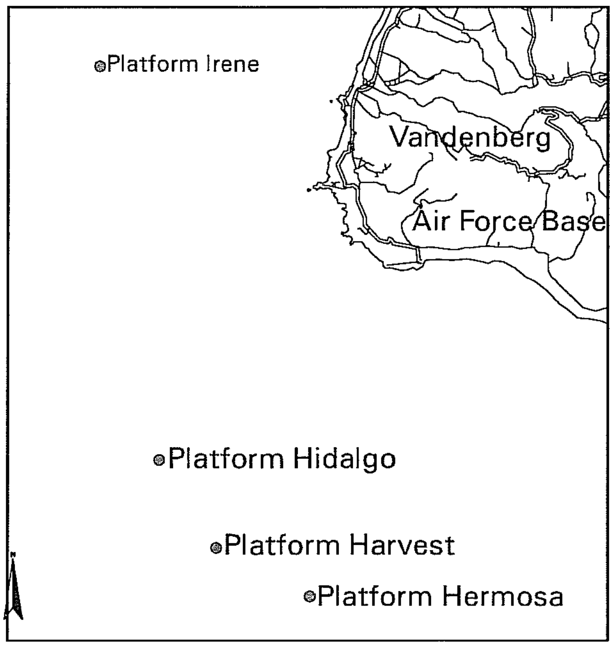
1.2 Facility Overview

1.2.1 Facility Overview: Platform Hidalgo is located on offshore lease tract OCS-P-0450, approximately seven miles offshore of Point Arguello, California (Latitude 34°29'42.06" North, Longitude 120°42'08.44" West). The platform is situated in the Southern Zone of Santa Barbara County. Figure 1.1 shows the relative location of Platform Hidalgo off the Santa Barbara County coast.

[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.

Figure 1.1 - Location Map for Platform Hidalgo





The eight leg, five deck platform lies in 430 feet of water and was installed in 1986. Initial production commenced in 1991 and as of October 16, 2000, eleven wells have been drilled on Hidalgo. Platform Hidalgo is a self-contained, manned drilling and producing platform with (1) locations for a maximum of 56 well slots, (2) facilities for gas and oil production, and (3) accommodation quarters for crew. Produced oil from Platform Hidalgo is shipped via submarine pipeline to Platform Hermosa for subsequent transfer to shore and to the Gaviota Oil Heating Facility (GOHF).

The production systems on Platform Hidalgo are capable of processing approximately 35,000 barrels per day (bpd) of wet oil (i.e., oil/water emulsion) and approximately 28.0 million standard cubic feet per day (MMscfd) of natural gas. Gas is separated from oil emulsion on the platform and is dehydrated. Oil emulsion undergoes initial processing to reduce water and sediment content prior to being pumped through a 16-inch pipeline for a distance of 4.8 miles to Platform Hermosa, then to PXP's GOHF. Hidalgo's gas is used as fuel or is reinjected.

The Point ArguelloProject is comprised of the following facilities:

Platform Hermosa: Installed in 1985 by Chevron and operated by PXP. This platform is subject to PTO 9104.

Platform Hidalgo. Installed in 1986 by Chevron and operated by PXP. This platform is subject to PTO 9105.

Platform Harvest: Installed in 1985 by Texaco and currently operated by PXP. This platform is subject to PTO 9103.

Gaviota Oil Heating Facility (GOHF): Installed in 1989 by Chevron and operated by PXP. This facility is subject to PTO 5704.

Offshore Pipelines: The pipelines include both oil and gas lines from the platforms to the GOHF. These pipelines were installed in 1988 and are operated by PXP.

1.2.2 Facility New Source Review Overview: Since the issuance of the initial Part 70 operating permit on April 19, 2001, the following permitting actions haven occurred. Each of these permitting actions are incorporated into this permit.

ATC/PTO 9105-01: This permit authorized the removal of the unplanned flaring sulfur concentration limit of 10,000 ppmv. The APCD determined that compliance for unplanned flaring can be determined through the permitted mass emission limits alone.

ATC/PTO 9105-09: This permit authorized revisions to the visible emissions monitoring requirements listed in permit condition 9.B.2.

ATC/PTO 9105-10: This permit authorized an increase in the number of allowable pigging vents.

ATC/PTO 10851: This permit authorized corrections to turbine fuel use calculations.

***ATC/PTO 10775*:** This permit authorized revisions to the number of fugitive leakpaths.

***ATC/PTO 11082*:** This permit authorized an increase in the number of turbine starter operating hours.

***ATC/PTO 11662*:** This permit authorized an increase in the number of pigging events and pigging emissions.

***PTO 11932*:** This permit authorized the installation of one emergency firewater pump and two emergency electrical generators due to the loss of the Rule 202.F.1.d exemption. One of the emergency electrical generators (APCD Device #108083) has been removed from site and therefore is not included in this permit..

PTO 9105-13: Replacement of MERC emission reduction credits with credits generated by the installation of emission controls on gas operated turbines on Platform Harvest.

PTO 9105-14: Use of a temporary equivalent replacement air flotation cell.

***Trn O/O 9105-07*:** This permit authorized of a change of Project Ownership, Inc. (removal of Texaco Harvest, LLC)

***Trn O/O 9105-08*:** Transfer of Platform Operatorship from Arguello, Inc. to Plains Exploration and Production Co. (PXP)

1.3 Emission Sources

The emissions from Platform Hidalgo come from combustion sources, storage tanks and piping components, such as valves and flanges. Section 4 of the permit provides the APCD's engineering analysis of these emission sources. Section 5 of the permit describes the allowable emissions from each permitted emissions unit and also lists the potential emissions from non-permitted emission units.

The emission sources include:

- Four turbine generators used for electrical power generation. The turbines typically burn sweetened natural gas, however diesel fuel may be used during times when the natural gas supply has been interrupted.
- Four diesel fired turbine starter engines.
- Two 50-ton pedestal cranes operated by diesel-driven internal combustion engines.
- A standby diesel-driven generator that is used only in emergency situations.
- A standby diesel-driven fire water pump that is used only in emergency situations.
- Crew, supply, and emergency response boats.
- High Pressure and Low Pressure Flares.
- Helicopters.
- Solvent cleaning.

A list of all permitted equipment is provided in Attachment 10.3.

1.4 Emission Control Overview

Air quality emission controls are utilized on Platform Hidalgo for a number of emission units. The emission controls employed on the platform include:

- An Inspection & Maintenance program for detecting and repairing leaks of hydrocarbons from piping components, consistent with the requirements of Rule 331, to reduce ROC emissions by approximately 80-percent.

- Use of turbo-charging, enhanced inter-cooling and 4° timing retard on the crew and supply boat main engines to achieve a NO_x emissions rate of 8.4 g/bhp-hr. ,. The newer technology on the Santa Cruz supply boat achieves 5.99 g/bhp-hr without these controls.

- Use of turbo-charging, inter-cooling and 4° timing retard on the pedestal crane engines to achieve a NO_x emissions rate of 8.4 g/bhp-hr.

- A vapor recovery system to collect evaporating reactive organic vapors from various tanks and vessels and deliver them to the gas compression system.

- Water injection in the turbines G-91, G-92 and G-93 to reduce NO_x formation by approximately 70-percent.

1.5 Offsets/Emission Reduction Credit Overview

Offsets: Offsets are required for the Point Arguello Project and are discussed in detail in Section 7.3.

Emission Reduction Credits: Platform Hidalgo provides ERCs through an enhanced fugitive hydrocarbon inspection and maintenance program on the specific gas service valves and associated connections. By implementing this enhanced program, PXP has created 0.79 tons per year of reactive organic compound emission reduction credits. These ERCs have been registered pursuant to APCD Rule 806 through the issuance of DOI 0003 and ERC Certificate No. 0005.

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 Tables 3.1 and 3.2 for a list of federally-enforceable requirements*)

1.6.2 Insignificant Emissions Units: Insignificant emission units are defined under APCD Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. 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 5.4 for the federal PTE for this source)*

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

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

1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally-enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on or before March 1st or on a more frequent schedule specified in the permit. Each certification is signed by a "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit. *(see Section 1.6.9 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. *(see Section 4.9.3, CAM Rule).*

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

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

Thomas Goeres, Operations Manager
201 South Broadway
Orcutt, CA 93455

2.0 PROCESS DESCRIPTION

2.1 Process Summary

2.1.1 *Production*: The well bays are arranged in two groups with 56 total well slots. Flow lines from wells in each group are connected to identical manifold systems (East Bay and West Bay). The manifolds allow flow from the wells to be switched to either the production or test separation systems. Lines for well cleanup, casing gas recovery or gas lift, hydraulic control, and associated instrumentation are provided for each wellhead. Initially, each well flowed under its own pressure. All producing wells now require gas lift.

Two types of crude oils are produced from different portions of the oil reservoir. Light crude (32° API) is produced from the northern portion, and heavier crude (20° API) is produced from the southern portion.

2.1.2 *Gas, Oil and Water Separation*: Two separation systems are in operation on Platform Hidalgo: (1) the production separation system and (2) the test separation system. The production separation system is described in this section, while the test separation system is described in the section dealing with well testing and maintenance.

There are three modes of operation: mixed mode, segregated mode, and free water knockout mode. In the mixed mode, the production fluids from the light and heavy production headers are commingled and fed to either one of the production preheaters, E-1 or E-2. Heated production fluids then flow to one of the production separators, V-1 or V-2, where phase separation is accomplished. In this production mode, the second production preheater and the second production separator are in standby or parallel service.

In the segregated mode of operation, the fluids from the light production header are fed to the preheater E-1 and production separator V-1, while the fluids from the heavy production header are fed to preheater E-2 and production separator V-2. In this mode, either light or heavy production may be diverted to preheater (E-3) and the large test separator (V-3), which are designed to take either total light or total heavy production.

When the water production has increased to a certain level, the free water knockout mode may be used. In this mode, the two production separators (V-1 and V-2) would be operated in series, with the majority of the water being removed in the first vessel and the remaining water being removed in the second vessel. This two-stage processing would ensure that the water content of the oil will not exceed the specification limit of 3-percent water cut. The production separators and the large test separator all operate at approximately 120 psig.

The preheaters are designed to heat the production fluids from approximately 100°F to 190°F. The production separators operate from approximately 85 to 140 psig and 190°F with a capacity of 50,000 bpd of oil emulsion and 28 MMscf of gas. Gas from the top of the separators is compressed in the second stage of the main gas compressors (K-12 and K-13). The water level is automatically controlled, with the excess being drained off the bottom of the separator, collected in the produced water header, and sent to the produced water corrugated plate interceptors (CPI) separator for further processing. The crude oil is separated from the water and flows to the wet oil surge tank (V-8) for subsequent metering, sampling, and pumping to Platform Hermosa, and from there to the onshore facilities.

Condensate from the gas scrubbers (V-10, V-11, V-12, V-13 and V-14) is routed to the wet oil surge tank (V-8) or to V-71/ V-72 for dehydration and then shipped to V-8. Liquids from the dirty oil transfer pumps (P-74 and P-80), well cleanup separator (V-9) and low temperature separator (V-86) are recycled into the crude oil header upstream of the production preheaters (E-1 and E-2).

2.1.3 *Waste Water Treatment*: The produced water treatment system on Platform Hidalgo consists of the produced water CPI separators (M-32 and M-33), air flotation cell (M-31), produced water surge tank (T-31), and the disposal pile (T-75). Deck drainage and liquids collected in the sump are routed to the oily water CPI separator (M-70) and then to the disposal pile (T-75).

2.1.4 *Well Testing and Maintenance*: The test separation system is used to determine the output of a well and the amount of demulsifying agent and operating conditions necessary to optimize separation of gas, water, and sediment from a well. Each well is tested on initial start-up and periodically thereafter to determine the trend of a well's oil, gas, and water production.

Two test separator systems are provided on Platform Hidalgo. Crude oil from the small test headers is treated in one of the small test separators (V-4 and V-5) and then added back to the production stream (E-1/E-2). Crude oil from the large test header is treated in the large test separator (V-3); the large test separator can be used as a standby production separator in segregated operating mode, but is normally used as a test separator. The systems are similar to the production separation systems described above, but are designed for production from only one well at a time and are of lower capacity.

The primary function of the well cleanup system is to remove produced fluids and solids from new and reworked wells before bringing the wells into production in the production separation system. The well cleanup system forwards crude oil associated with BS&W (basic sediment and water) to the dirty oil storage vessels before processing in the production separation system. All wells are connected to the well cleanup header. The system is designed for either continuous or intermittent operation.

The well cleanup separator (V-9) receives produced fluids and contaminated solids from the wellhead to bring in or clean up a well. The produced fluid stream is not heated and flows either to the dirty oil storage vessels (V-71 and V-72) or to a production heater for further processing.

The dirty oil storage vessels are cylindrical vessels maintained under a small positive pressure (2.0 psig) by blanket gas; each vessel has a capacity of 300 bbl. The solids are drawn off the bottom, slurried with jet water from the jet water pumps (P-35 and P-36), and pumped either to the disposal well (C-9) or to the disposal bins for removal from the platform. The dirty oil is pumped from the dirty oil storage vessels by the dirty oil transfer pumps (P-74 and P-80) to the production preheaters (E-1 and E-2) for further processing. In the condensate handling mode, the water is injected into C-9 and the condensate is then shipped to V-8 via P-74 or P-80.

2.1.5 *Emulsion Breaking and Crude Oil Storage*: The primary function of the oil shipping, metering, and pipeline system is to pump and record the amount of crude oil shipped from the platform.

The lease automatic custody transfer (LACT) units continually register the oil shipped from the platform. A bi-directional positive displacement meter prover is used to prove the meters.

The oil pipeline system also includes pig receivers and a pig launcher for pigging the oil pipelines with various types of pigs to remove water and solids from the oil pipeline.

2.1.6 *Crude Oil Shipping*: The wet oil surge tank (V-8) has three functions: separate flash gases and free water from the oil, provide a small reservoir of crude (approximately 15 minutes at full pumping capacity), and maintain a liquid suction head to the oil charge pumps (P-4, P-5, and P-6). The oil charge pumps pump the oil at 250 gpm and 250 psig to the shipping pumps through the LACT units and meter prover. The shipping pumps raise the pressure to about 500 psig for pipeline transfer to Platform Hermosa.

In segregated production mode, heavy crude oil is pumped using one of the rotary shipping pumps (P-1 or P-2), whereas light crude oil is pumped using one of the centrifugal shipping pumps (P-7 or P-8). In mixed production mode (normal), the mixed crude is pumped using any two of the three LACT charge pumps.

2.1.7 *Gas Dehydration and Compression*: The main gas compression system compresses the high-pressure gas from the separation systems, the low-pressure gas from the vapor recovery system, and high pressure gas supplied from Platform Harvest and Platform Hermosa via the pipeline. Compressor K-12 has five stages of compression; Vapor, MGC 1,2,3, and 4, and develops 3000 psi discharge pressure. K-13 has four stages of compression; vapor, MGC 1, 2 and 3, and develops 1,250 psi discharge pressure. The gas is utilized for stimulation purposes as gas lift for the producing wells at 1,250 psi with the balance being injected as storage into injection well C-1 at 3,000 psi. The total gas stream is treated to reduce the water dew point to less than 40° F. A slipstream of produced gas from the main gas compressor second stage discharge is sweetened in the amine contactor for use as fuel gas and blanket gas. In an alternative operating scenario, gas normally injected at well C-1 could be transferred to Platform Harvest (via Platform Hermosa) for injection.

Two 100-percent reciprocating gas compressors (K-12 and K-13) are used for main gas compression. Each compressor has four compressor cylinders and is driven by a 3,000 hp variable speed electric motor.

The hot compressed gas streams are cooled in shell and tube heat exchangers, and are scrubbed after each stage. Five scrubbers (V-10, V-11, V-12, V-13, and V-14) serve to "knock out" liquids, including both water and natural gas liquids (NGL or condensate). Some portion of the gas is delivered from the MGC stage 2 discharge to the amine unit where it is sweetened for use as fuel gas. After scrubbing in the third stage discharge scrubber (V-14), gas is sent to the glycol contactor to reduce water vapor.

The glycol dehydration and regeneration system dehydrates the gas using triethylene glycol and then regenerates the glycol. The wet gas from the gas compressors flows to the glycol contactor (V-16), a trayed vertical tower located on the wellhead and mezzanine decks. Rich glycol (96-percent weight triethylene glycol) from the glycol contactor and the dry gas scrubber (V-17) is flashed in the glycol flash tank to remove the majority of the dissolved hydrocarbons. The hydrocarbon vapors are returned to the VRU system.

The rich glycol is heated and goes to the still section of the glycol regenerator (E-16). The regenerator heats the glycol to 385°F by a heating medium heat exchanger, thereby reconcentrating the glycol. The lean glycol is cooled and returned to the glycol contactor by the glycol pumps.

2.1.8 *Gas Sweetening and Sulfur Recovery*: Fuel gas for use by the turbine-driven electrical generators is produced as a sidestream of the main gas compression system. The gas is sweetened in the amine fuel gas treatment and regeneration system; the amine unit uses diethanolamine (DEA) to remove H_2S and CO_2 from the production gas. Feed stock to the amine system is a sidestream from the MGC; the sour gas enters the amine contactor (V-20) and is sweetened to a specification of less than 50 ppmv H_2S.

The amine contactor contains three stacked sections for a total packing height of 40 ft. The rich amine flows from the contactor to the amine flash tank where dissolved hydrocarbons are removed by flashing at reduced pressure. Rich amine is regenerated in the amine regenerator (V-22), cooled and filtered, and returned to the amine contactor.

2.1.9 *Vapor Recovery Systems*: The vapor recovery system collects vapors from various tanks and vessels and delivers them to the gas compression system.

2.1.10 *Heating and Refrigeration*: There are no fuel-fired process heaters or process refrigeration systems on Platform Hidalgo. Waste heat recovery (H-92, H-93, H-94) from the turbine exhaust is used to heat fluid, which is circulated by pumps (P-92 or P-93) through crude oil exchangers (E-1, E-2, E-3, E-4, E-5) and Glycol Regenerator (E-16).

2.1.11 *Flare Relief System*

2.1.11.1 *Flare System Design*: Platform flaring is performed to safely dispose of excess gas created by planned or unplanned (upset) conditions. The relief and flare system collects process vent and relief streams from all hydrocarbon systems for safe, continuous burning at the flare.

The high-pressure flare tips (M-12) and low-pressure tip (M-13) are low radiation types manufactured by Kaldair, and emit about 1000 Btu/hr/ft^2 of radiant heat. The tips use the "Coanda Principle" which entrains large volumes of air resulting in a short, stable flare that burns with low radiation and no smoke. Each tip is furnished with two dual pilots, which are ignited from the high-pressure flame front generator. The system is designed for the pilots to re-ignite automatically in the case that they are blown out by high winds. Sweet fuel gas is used for pilot flame ignition and purge.

2.1.11.2 *Planned Flaring Scenarios*: There are four common or routine planned flaring scenarios that occur on Platform Hidalgo:

(1) During the start-up of each unit is manually initiated to sweep atmospheric air from the system. This minimizes the possibility of having combustible gas mixtures in the process.

(2) During the shut down of equipment, shut down valves (SDV's) will close and blowdown valves (BDV's) will open automatically to release pressure from the system. This is a requirement of federal regulations.

(3) During maintenance of equipment, the systems are purged with nitrogen or fuel gas and blown down to the flare system.

(4) During peak operations, low-pressure gas (2-115 psig) and blanket gas is released from the low-pressure vents if process set-points are exceeded.

All vents from production process equipment, tanks, relief valves, burst plates, and similar devices are piped to the flare system. Flaring due to pigging operations may occur up to two times per day with each event lasting for as long as about 18 minutes. Pig receivers are purged with sweet gas, thus reducing the sulfur content of the flared gas associated with pigging to levels of less than 50 ppmv as H_2S.

Flaring due to planned oil train shutdown may occur four times per year with each event lasting approximately four hours. Flaring caused by planned and controlled gas plant shutdown may occur once per year and last for approximately five hours. Flaring due to gas-fired pilots occurs continuously. Flaring may also occur due to testing of safety devices as required by the Minerals Management Service and equipment shutdowns for preventive maintenance.

2.1.11.3 Unplanned Flaring Scenarios: Unplanned flaring events on Platform Hidalgo most commonly derive from equipment shutdowns. Each system after blowing down will initiate a purge cycle before start-up. These equipment shut downs are directly related to the instrumentation set point tolerances imposed by federal regulations. Unplanned, breakdown, or emergency flaring events are defined as all flaring that does not meet the definition of planned flaring under Rule 359.

2.2 Support Systems

2.2.1 *Pipelines*: The pipelines associated with the platform include a 16-inch oil emulsion line and a 10-inch produced gas line to/from Platform Hermosa.

2.2.2 *Power Generation*: Electrical power for platform operations is provided by three 2,800 kW Solar Centaur dual-fuel turbine generators (G-91, G-92, and G-93) and one 3,100 kW Solar SoLoNOx gas-only turbine (G-94). The dual-fuel turbines can be run on either produced gas or diesel fuel and use water injection for NO_x control. The SoLoNOx unit employs a dry low-NO_x technology. An emergency diesel driven generator (G-90), also located on the main deck of the platform, provides standby power.

2.2.3 *Supply Boats*: Supply boats regularly service the Point Arguello platforms on the same round trip from Port Hueneme. Two vessels are designated as dedicated project vessels and are fitted with emission controls on the main engines as described in Section 4.4 below. Other supply boats may be used provided the main engines meet the controlled emission factor and the total boat potential to emit (all engines) is demonstrated to be under the permitted supply boat emissions .

2.2.4 *Crew Boats*: Transfer of crew to and from Platform Hidalgo normally occurs by helicopter and crew boats are used only when weather prohibits flying or if there are unusually large numbers of crew to be transferred.

2.2.5 *Helicopters*: Crew transport is normally accomplished by helicopter from the Santa Maria Airport.

2.3 Drilling Activities

2.3.1 *Drilling*: Drilling activities occur periodically.

2.3.2 *Well Workover*: Current operations include a variety of well workover projects. These projects include redrilling or sidetracking of existing wells, acidizing of existing well perforations and optimizing gas lift zones.

2.3.3 *Enhanced Recovery*: Enhanced oil recovery techniques are employed in the form of artificial gas lift. Electrical submersible pumps may be used in the future to supplement gas lift.

2.4 Maintenance/Degreasing Activities

2.4.1 *Paints and Coatings:* There is a maintenance painting program that is in progress on Platform Hidalgo. Pollution prevention measures are in effect; tarps are used to help create a more controlled environment and all solvents are recycled or properly disposed.

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

2.5 Planned Process Turnarounds

Process turnarounds on platform equipment are scheduled to occur when the onshore receiving facilities are required to shut down for maintenance. Major pieces of equipment such as gas compressors, turbine generators, and coolers have maintenance schedules specified by the manufacturer, and that equipment is removed from service, inspected, and repairs are made as necessary. Maintenance of critical components is carried out according to the requirements of Rule 331, Fugitive Emissions Inspection and Maintenance. The emissions from planned process turnarounds are incorporated in the emissions category for planned flaring.

2.6 Other Processes

PXP has stated that no other processes exist that would be subject to permit.

2.7 Detailed Process Equipment Listing

Refer to the tables in Attachment 10.3 for a complete listing of all permitted and exempt emission units.

3.0 Regulatory Review

This Section identifies the federal, state and local rules and regulations applicable to Platform Hidalgo.

3.1 Rule Exemptions

➔ *APCD Rule 202 (Exemptions to Rule 201)*: PXP has requested a number of 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 were either approved by the APCD or may apply to individual equipment units meeting the exemption criteria:

- Section 202.L.1 for heat exchangers, production and test preheaters (E-1 through -5), shipping pump recycle oil cooler (E-6), wet oil surge vessel start-up heater (E-8), vapor recovery system discharge coolers (E-10), main gas compressor discharge coolers (E-11, E-12, E-13), glycol handling and regeneration exchangers (E-14, E-15A, E-15B, E-15C, E-16, E-17, E-22), amine handling and regeneration exchangers (E-18 through -20, E-21A, E-21B), vapor recovery stage suction cooler (E-23), internal heater dirty oil storage vessel (E-71, E-72) and fuel gas preheater (E-90).

- Section 202.V.2 for two diesel storage tanks (T-90 and T-91).

- Section 202.V.3 for one compressor lubricating oil storage tank (T-10).

➔ *APCD Rule 321 (Control of Degreasing Operations)*: Per Section J.2, an exemption for all solvent degreasers with a liquid surface area of less than 929 square centimeters (1.0 square foot).

➔ *APCD Rule 331 (Fugitive Emissions Inspection and Maintenance)*: The following exemptions were applied for and approved by the APCD:

- Section B.2.c for one-half inch and smaller leak-free stainless steel tubing fittings.

- Section B.3.a for components exclusively in heavy liquid service.

- Section B.3.b for air flotation cell components when used in nitrogen gas blanket mode.

➔ *APCD Rule 333 (Control of Emissions from Reciprocating Internal Combustion Engines)*: Under Section B.1.b, engines exempt per Rule 202 are also exempt from the requirements of this rule.

➔ *APCD Rule 359 (Flares and Thermal Oxidizers)*: Under Section D.1.b, PXP has obtained APCD approval to comply with the exemption from Section D.1.a requirements and has offset all excess SO_x emissions at a ratio of 1:1. This was originally accomplished through the Marine Engine Repowering Campaign (MERC), in which the gasoline engines of a number of small fishing vessels were replaced with clean burning diesel engines. These MERC ERCs were subsequently replaced with ERCs created through controlling natural gas turbines on Platform Harvest as described in section 7.3. Unplanned flaring is exempt from the sulfur standards of this rule.

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)*}: Platform Hidalgo was constructed and permitted prior to the applicability of these regulations. However, all permit modifications as of September 4, 1992 are subject to APCD NSR requirements. Compliance with APCD Regulation VIII (*New Source Review*), ensures that future modifications to the facility will comply with these regulations.

3.2.2 40 CFR Part 55 {*OCS Air Regulation*}: PXP is operating Platform Hidalgo in compliance with the requirements of this regulation.

3.2.3 40 CFR Part 60 {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 NOx 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 0.1 % (as a worst case) based on diesel and gas turbine fuel data ranging from 0.1 to 0.6 % nitrogen content.

To determine the specific requirements for monitoring under this subpart, the APCD reviewed past source test results for these turbines for operations on both natural gas and diesel fuel. The source test results indicated that the worst case *uncontrolled* NO_x emission rate was 172 ppmv at 15% O_2 while operating on diesel. Thus, since these turbines operate in compliance with the 190 ppmv standard without control, water injection is not required for compliance with GG. Consequently, the monitoring and reporting requirements in subpart GG 60.334 are not applicable to these turbines.

In any case, water injection, monitoring, and reporting have historically been required for these turbines (except G-91). Monitoring of the water injection is performed by the platform Automated Data Gathering System (ADGS). Recordkeeping and reporting requirements are summarized in condition 9.C.2 of this permit and in the Turbine ADGS Quality Assurance Plan.

3.2.4 40 CFR Part 61 {*NESHAP*}: None of the equipment in this permit are subject NESHAP requirements.

3.2.5 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. In a February 20, 2003 correspondence PXP requested exemption from this subpart and provided information to support the request. The APCD approved the exemption on this date. This exemption requires that records be maintained in accordance with 40 CFR 63.10(b)(3).

3.2.6 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. This facility's HAP emission totals are less than each of the above thresholds and therefore, this subpart is not applicable. See Section 5.6 for HAPs emission totals.

3.2.7 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998. Turbines G-92 and G-93 are subject to this rule. The primary requirement is the submittal of a CAM Plan identifying specific operational parameters to be monitored and serve as compliance indicators for emission limits. See section 4.11.3 for a discussion of the plan and the rule applicability determination.

3.2.8 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to Platform Hidalgo. Table 3.1 lists the federally-enforceable APCD promulgated rules that are "generic" and apply to Platform Hidalgo. 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 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.

3.2.9 Airborne Toxic Control Measure (ATCM) for Stationary Compression Ignition (CI) Engines (CCR Section 93115, Title 17): This applies for all diesel engines rated over 50 brake horsepower located at this OCS facility. See discussion in section 3.3.3 below.

3.3 Compliance with Applicable State Rules and Regulations

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

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 Platform Hidalgo are required to conform to these standards. Compliance is assessed through onsite inspections. These standards are APCD-enforceable only. 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 over 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. Compliance shall be assessed through onsite inspections and reporting. The operating requirements and emission standards outlined in the ATCM do not apply to stationary diesel-fueled engines solely used on the OCS. However, these OCS engines are required to meet fuel, recordkeeping, reporting, and monitoring requirements outlined in the ATCM. On January 30, 2006 the DICE ATCM was incorporated into 40 CFR Part 55, making the requirements of the DICE ATCM federally enforceable in the OCS.

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 Platform Hidalgo. 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 Platform Hidalgo:

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 APCD 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 which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringlemann 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 Ringlemann Chart. Sources subject to this rule include: the flare and all diesel-fired piston internal combustion engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance is assured by requiring all engines to be maintained according to manufacturer maintenance schedules.

Rule 303 - Nuisance: This rule prohibits the OCS operator from causing a public nuisance due to the discharge of air contaminants. Based on the source's location on the OCS, the potential for public nuisance is small.

Rule 305 - Particulate Matter, Southern Zone: Platform Hidalgo is considered a Southern Zone source. This rule prohibits the discharge into the atmosphere from any source particulate matter in excess of specified concentrations measured in gr/scf. The maximum allowable concentrations are determined as a function of volumetric discharge, measured in scfm, and are listed in Table 305(a) of the rule. Sources subject to this rule include: the flare and all diesel-fired IC engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance is assured by requiring all engines to be maintained according to manufacturer maintenance schedules. Rule 359 addresses the need for the flare to operate in a smokeless fashion.

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

Rule 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. No measured data exists to confirm compliance with this rule, however, all produced gas from Platform Hidalgo is collected for sales, re-injection or is collected by vapor recovery (i.e., no venting occurs). As a result, it is expected that compliance with this rule will be achieved.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted on Platform Hidalgo to 0.5-percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H_2S) {or 239 ppmvd} for gaseous fuels. All piston IC engines on the Platform Hidalgo and on the crew and supply boats are expected to be in compliance with the liquid fuel limit as determined by fuel analysis documentation. The flare relief system is not subject to this rule (see discussion under Rule 359).

Rule 317 - Organic Solvents: This rule sets specific prohibitions against the discharge of emissions of both photochemically and non-photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used on the platform 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 318 - Vacuum Producing Devices or Systems – Southern Zone: This rule prohibits the discharge of more than 3 pounds per hour of organic materials from any vacuum producing device or system, unless the organic material emissions have been reduced by at least 90-percent. PXP has stated that there is no equipment subject to this rule.

Rule 321 - Solvent Cleaning Operations: This rule sets equipment and operational standards for degreasers using organic solvents. There is one remote reservoir degreasing unit (cold solvent cleaning) on the platform. This unit is exempt from all provisions of this rule with the exception of Section G.2 (requirement to keep the unit covered at all times when not in use). Degreaser compliance and solvent use are determined through APCD inspection and the operating and recordkeeping requirements of the rule.

Rule 322 - Metal Surface Coating Thinner and Reducer: This rule prohibits the use of photochemically 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 the application of surface 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 comply with the Administrative requirements under Section F for each container on the platform.

Rule 324 - Disposal and Evaporation of Solvents: This rule prohibits any source from disposing more that one and a half gallons of any photochemically reactive solvent per day by means that will allow the evaporation of the solvent to the atmosphere. PXP is required to maintain records to ensure compliance with this rule. Solvents used during operations (e.g., for degreasing and wipe cleaning) are limited to the non-photochemically reactive type.

Rule 325 - Crude Oil Production and Separation: This rule, adopted January 25, 1994, applies to equipment used in the production, processing, separation, gathering, and storage of oil and gas prior to custody transfer. The primary requirements of this rule are under 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. Production and test separators are all connected to gas gathering systems and relief valves are connected to the flare relief system. Compliance with Section E is met by directing all produced gas to sales, injection, gas lift or to the flare relief system.

Rule 326 - Storage of Reactive Organic Liquids: This rule applies to equipment used to store reactive organic compound liquids with a vapor pressure greater than 0.5 psia. There is no platform equipment subject to this rule.

Rule 327 - Organic Liquid Cargo Tank Vessel Loading: There are no organic liquid cargo tank loading operations associated with Platform Hidalgo.

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 Point Arguello Project Stationary Source emits to the atmosphere more than 5 lb/hr of non-methane hydrocarbons, oxides of nitrogen and sulfur oxides and more than 10 lb/hr of particulate matter, thereby triggering the Section C.2 requirement that the need and application of CEMs be evaluated. With the exception of the continuous monitoring of fuel gas H2S as described in section 4.11 below, the APCD has determined that CEMS are not required to assess compliance for Platform Hidalgo.

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. It is not anticipated that PXP will trigger the requirements of this rule. Compliance shall be based on site inspections.

Rule 331 - Fugitive Emissions Inspection and Maintenance: This rule applies to components in liquid and gaseous hydrocarbon service at oil and gas production fields. Ongoing compliance with the provisions of this rule is assessed through implementation of the most current version of the APCD-approved Fugitive Inspection and Maintenance Plan, platform inspection by APCD personnel using an organic vapor analyzer and through analysis of operator records. Platform Hidalgo does not perform any routine venting of hydrocarbons to the atmosphere.

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. The diesel-fired pedestal crane engines on Platform Hidalgo are subject to the

NO_x standards under Section E.4 of 700 ppmvd at 15-percent oxygen. Ongoing compliance is achieved through implementation of the most current version of the APCD-approved Rule 333 Inspection and Maintenance Plan required under Section E and through biennial source testing. The emergency generator and firewater pump are exempt per section B.2 since they are limited to 200 hours per year of operation.

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. The only vessels to which this rule applies are the production surge tanks. Ongoing compliance with this rule is achieved through the section F and G reporting and recordkeeping requirements of the rule.

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

§ D.1 - Sulfur Content in Gaseous Fuels: Part (a) limits the total sulfur content of all planned flaring from South County flares to 15 gr/100 cubic feet (239 ppmv) calculated as H_2S at standard conditions. The platform produces sweet gas which provides the flare with purge and pilot gas that is within the limits of this rule. For all other planned emissions associated with platform flaring volumes, PXP has obtained APCD approval to comply with the part (b) exemption of this rule that requires excess SO_x emissions to be offset at a ratio of 1:1. Unplanned flaring is exempt from the sulfur standards of this rule.

§ D.2 - Technology Based Standard: Requires all flares to be smokeless and sets pilot flame requirements. The flare on Platform Hidalgo is in compliance with this section.

§ D.3 - Flare Minimization Plan: Reduction in the volume of flare gas is attained through implementation of the APCD-approved Flare Minimization Plan.

Rule 505 - Breakdown Conditions: This rule describes the procedures that PXP must follow when a breakdown condition occurs to any emissions unit associated with Platform Hidalgo. 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 360 – Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers. This rule applies to water heaters, boilers, steam generators and process heaters with rated heat input capacities greater than or equal to 0.75 MMbtu/hr up to, and including, 2.0 MMbtu/hr. There are no unit at this facility subject to this rule.

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 a revised Emergency Episode Plan in June 2008.

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 file.

3.5.1 Facility Inspections. Platform Hidalgo is inspected by the APCD each calendar quarter. Since the previous permit renewal, with the exception of the enforcement actions documented below in section 3.5.3, each quarterly inspection indicates that Platform Hidalgo has operated in compliance with APCD rules, regulations and the permit conditions of this permit.

3.5.2 Variances: There has been one significant variance issued for Platform Hidalgo since the last permit renewal as listed below:

Variance Order 50-06R: Violation of PTO 9103 Permit Condition 9.C.10.
Variance Date: 11/01/06. Expiration of MERC ERCs. Compliance verified 10/03/2007.

3.5.3 Violations: Since issuance of the last Part 70 permit renewal the following enforcement actions have been issued:

NOV No. 8386: Violation of Rule 323. Issued 07/19/05. Application of architectural coating containing ROCs in excess of the rule limits.

NOV No. 8387: Violation of Rule 323. Issued 07/22/05. Application of architectural coating containing ROCs in excess of the rule limits.

AI DOC No. 8769: Violation of Rule 331. Issued 09/21/06. Failure to conduct fugitive I&M inspections on components subject to Rule 331.

3.5.4 Significant Historical Hearing Board Actions: There have been no significant historical Hearing Board actions since issuance of the initial Part 70 permit in April 2001.

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, as listed in form 1302-H of the Part 70 application	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 applications.	Addition of new equipment of modification to existing equipment.
RULE 212: Emission Statements	All emission units	Administrative
RULE 301: Circumvention	All emission units	Any pollutant emission
RULE 302: Visible Emissions	All emission units	Particulate matter emissions
RULE 305: PM Concentration – South 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 operations.
RULE 318: Vacuum Producing Devices – Southern Zone	All systems working under vacuum	Operating pressure

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 321: Solvent Cleaning Operations	Cold solvent cleaning unit EQ No. 14-2	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 505.A, B1, D: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	PXP – Point Arguello Project is a major source.
REGULATION VIII: New Source Review	All emission units	Addition of new equipment of modification to existing equipment. Applications to generate ERC Certificates.
REGULATION XIII (RULES 1301-1305): Part 70 Operating Permits	All emission units	PXP – 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. 9-1, 10-1, 10-2, 11-1, 12-1, 12-2	All pre-custody production and processing emission units
RULE 331: Fugitive Emissions Inspection & Maintenance	EQ Nos. 4-x, 5-x	Components emit fugitive hydrocarbons.
RULE 333: Control of Emissions from Reciprocating IC Engines	EQ Nos. 1-1, 1-2, 1-3, 1-4, 1-5, 1-6, 1-7	IC engines exceeding 100 bhp rating.
RULE 359: Flares and Thermal Oxidizers	EQ No. 3-1, 3-2	Flaring
RULE 360: Emissions from Oxides of Nitrogen from Large Water Heaters and Small Boilers	None.	Units greater than or equal to 0.75 MMbtu/hr and less than or equal to 2.0 MMbtu/hr.

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	Administrative
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
RULE 361:Small Boilers, Steam Generators and Process Heaters	None.	Units rated greater than 2.0 MMbtu/hr and less than 5.0 MMbtu/hr.

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	January 21, 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 204	Applications	April 17, 1997
Rule 205	Standards for Granting Permits	April 17, 1997
Rule 206	Conditional Approval of Authority to Construct or Permit to Operate	October 15, 1991
Rule 208	Action on Applications - Time Limits	April 17, 1997
Rule 212	Emission Statements	October 20, 1992
Rule 301	Circumvention	October 23, 1978
Rule 302	Visible Emissions	June 1981

Rule No.	Rule Name	Adoption Date
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 318	Vacuum Producing Devices or Systems - Southern Zone	October 23, 1978
Rule 321	Solvent Cleaning Operations	September 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	December 14, 1993
Rule 331	Fugitive Emissions Inspection and Maintenance	December 10, 1991
Rule 333	Control of Emissions from Reciprocating Internal Combustion Engines	April 17, 1997
Rule 342	Control of Oxides of Nitrogen (NOx) from Boilers, Steam Generators and Process Heaters	April 17, 1997
Rule 343	Petroleum Storage Tank Degassing	December 14, 1993
Rule 344	Petroleum Sumps, Pits and Well Cellars	November 10, 1994
Rule 359	Flares and Thermal Oxidizers	June 28, 1994
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 No.	Rule Name	Adoption Date
Rule 901	New Source Performance Standards (NSPS)	May 16, 1996
Rule 903	Outer Continental Shelf (OCS) Regulations	November 10, 1992
Rule 1001	National Emission Standards for Hazardous Air Pollutants (NESHAPS)	October 23, 1993
Rule 1301	General Information	September 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 engineering analyses performed for this permit were limited to the review of:

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

Unless noted otherwise, default ROC/THC reactivity profiles from the APCD's document titled "*VOC/ROC Emission Factors and Reactivities for Common Source Types*" dated 7/13/98 (ver 1.1) was used to determine non-methane, non-ethane fraction of THC.

4.2 Stationary Combustion Sources

The stationary combustion sources associated with Platform Hidalgo consist of four turbines driven generators for electrical power generation, diesel fired internal combustion engines driving two 50-ton pedestal cranes, diesel-fired piston internal combustion engines driving an emergency generator and a standby fire water pump, four diesel-fired turbine start-up engines and the flare relief system.

4.2.1 *Turbines:* Electrical power for platform operations is provided by three 2,800 kW Solar Centaur T-4000 dual fuel turbine generators (G-91, G-92 and G-93) and one 3,100 kW turbine generator (G-94) that has been retrofitted with a dry low-NO_x combustor manufactured by Solar Turbines, Model 40-T4700S (SoLoNO_x). Turbines G-19, G-92 and G-93 can be fired on either produced gas or diesel fuel oil. Turbine G-94 is fired exclusively on produced gas.

Turbines G-91, G-92 and G-93: Emission calculation methodology for NO_x, ROC, and CO is a result of source test data. The algorithms listed below were developed from that data. The algorithm for the ROC emission rate for these turbines, while operating on fuel gas, has been revised during this 2008 permit renewal. It was revised to correctly reflect a turbine ROC emission rate of zero lbs/day while in the turbine is in an idle mode (zero kW).

For NO_x emission calculations:

$$ER_{fuel\ gas} = 1.0 + 0.02935(kW)^{0.668}$$

$$ER_{diesel} = 2.5 + 0.000801(kW)^{1.085}$$

For ROC emission calculations[2]:

$$ER_{fuel\ gas} = 0.5675 * (kW)^{0.03}$$

---

[2] Uncontrolled emissions are at operations less than 650 kW. Water injection starts for control purposes at 650 kW and the equation for controlled emissions is utilized.

$ER_{diesel} = 2.84 - (0.00058 X kW)$

For CO emission calculations:

$ER_{fuel\ gas} = (0.0014 X Kw) + 0.6242$

$ER_{diesel} = 1.2475 * e^{(0.0007 * kW)}$

Where:

ER = emission rate (lbs/hour)
kW = kilowatts

Emission factors for PM are from USEPA AP-42, Table 3.1-1.

Control of emissions from G-91, G-92 and G-93 is accomplished through maintaining limits on certain process parameters such as water-fuel injection rates. The SO_x emission factor is based on mass balance calculations. The sulfur content of the diesel is based on the California Code of Regulations standards for diesel fuel and is 0.0015 weight-percent or less. Produced gas burned in the turbines and the purge and pilot gas is not to exceed 50 ppmv total sulfur content expressed as hydrogen sulfide. The formation of NO_x in the turbine is reduced by at least 70-percent through the injection of deionized water into the combustion chamber. This permit requires a water-to-fuel ratio controller set-point at or greater than 0.80 pounds of water per pound of fuel when operating turbines G-91, G-92 or G-93 with either fuel gas or diesel at loads of 650 kW or greater. Water injection is initiated at loads of 500 kW or greater. Exhaust gas treatment for turbine NO_x is not employed.

The permittee, through the development approval process for the Point Arguello Project, has previously agreed to operate and maintain the turbines according to specific emission standards. These standards are incorporated into this permit.

Turbine G-94: NO_x emissions from SoLoNOx Turbine Generator G-94 shall not exceed 25 ppm_v (dry at 15% excess oxygen, measured at ISO conditions) when operated at loads greater than 50% of maximum rated capacity (1,550 Kilowatts) while operated on platform-produced natural gas. *[Re: PTO 9105-06]*

Control of NO_x from Turbine G-94 is accomplished through the use of a two-stage premixed design combustor with two flame zones, each receiving a constant fraction of the combustor air flow. Since the air/fuel mixture is premixed, the flame temperature is more consistent throughout the combustion zone, and can be more precisely controlled by the air/fuel mixture. Turbine G-94 is also equipped with a Predictive Emissions Monitoring System (PEMS), manufactured by Solar Turbines. The PEMS is used to estimate actual NO_x emissions from the turbine for emissions reporting purposes.

Turbine Source Testing: Testing of turbines G-91, G-92 and G-93 shall be conducted annually to determine compliance with permit conditions. All the turbines will be tested for concentrations (ppmv) and mass emission rates (lbs/hr) of NO_x, CO, and ROC on an annual basis. One turbine test will be conducted at 100-percent of safe operating load with water injection control while the turbine is fired on gas. The remaining turbines will be tested at historical operating loads with water injection control while the turbines are fired on gas. Testing on diesel fuel is required per the requirements of this permit. In addition, this permit provides the ability to exempt at most one turbine per year from testing if the prior year's annual operating time is less than 877 hours. Also, if at the time of source testing, a turbine is inoperable due to reasons beyond the reasonable control of the platform operator, that turbine shall be exempted from testing for that calendar year. Replacement turbines are required to undergo full matrix testing.

Turbine G-94 shall be tested at least once per calendar year. Testing shall be performed at the typical operating load over the previous 12-month period unless otherwise specified by the APCD, to demonstrate both the relative accuracy of the Predictive Emissions Monitoring System (PEMS) to within 15% as well as compliance with the emissions concentration and mass limits. If required by the APCD, uncontrolled emission factors may be confirmed during annual source testing as well.

During the 2005 permit renewal process, the higher heating value of the fuel gas was revised to 1211 Btu/scf to more closely reflect the actual fuel gas heating value. This resulted in revised fuel use limits for the turbines as documented in the 2005 permit renewal. During the 2008 permit renewal process it was noticed that a higher heating value of 1350 btu/scf was erroneously retained in the fuel use calculations for G-94. The fuel use calculations have been corrected as documented in Attachment 10.1 Reference I.
A review of fuel gas analyses submitted by PXP during 2006 and 2007 indicates that 1211 btu/scf reflects the current heating value of the fuel gas.

Monitoring, recording, and reporting of emission quantities are defined in Section 9 of this permit. Quality assurance for the monitors is defined in the *Point Arguello Project Turbine ADGS System Quality Assurance Plan.*

4.2.2 *External Combustion Equipment*: There is no external combustion equipment on Platform Hidalgo.

4.2.2 *Piston Internal Combustion Engines:* All platform internal combustion engines are diesel-fuel fired. The two pedestal crane engines are subject to permit and Rule 333 requirements. Other stationary IC engines on the platform: a standby electrical generator, four diesel-fired turbine start-up engines, and an emergency firewater pump, as well as three survival craft and one rescue boat. Temporary engines used to support drilling and well workover activities are expected to occur during the life of the platform. Applicability of permit requirements and associated controls for this temporary equipment will be determined according to the rules in effect at the time of use. The calculation methodology is similar for all stationary IC engines:

$$ER = [(EF * BHP * BSFC * FCF * HPP) \div 10^{6}]$$

where:

ER =	emission rate (lb/period)
EF =	pollutant specific emission factor (lb/MMBtu)
BHP =	engine rated max brake-horsepower (bhp)
BSFC =	engine brake specific fuel consumption (Btu/bhp-hr)
FCF =	liquid fuel correction factor, LHV to HHV

HPP = operating hours per time period (hrs/period)

The emission factor is an energy-based value use the higher heating value. As such, an energy based BSFC value must be also based on the HHV. Manufacturer BSFC data are typically based on LHV data and thus require a conversion (LCF) to the HHV basis. For diesel fuel oil, the HHV values are typically 6-percent greater than the corresponding LHV data. Volume or mass based BSFC data do not need any conversions.

4.2.3 *Crane Engines*: Identical Caterpillar Model 3408 DITA engines rated at 475 bhp drive both pedestal cranes. The emission factors for PM, CO and ROC are from USEPA AP-42, Table 3.3-1 (7/93) and the SO_x emission factor is based on mass balance calculation. The NO_x emission factor of 2.565 lb/MMBtu is based on the limit of 8.4 g/hp-hr found in APCD Rule 333. Crane and emergency generator NO_x emissions are controlled by turbocharging, 4° timing retard, and aftercooling.

Source testing shall be conducted biennially to determine concentrations (ppmv) and mass emission rates (lbs/hr) of NO_x, CO, and ROC from the two cranes engines. The cranes are tested under simulated maximum operating conditions.

Diesel fuel flow metering is accomplished by use of positive displacement meters on both crane engines, firewater pump, and stand-by generator. All permanent equipment, except flares, are fitted with elapsed non-resettable time meters for determining operating hours.

4.2.4 *Flare Relief System*: The flare relief system consists of a high pressure/low pressure flare manufactured by Kaldair with a low radiation type flare tip emitting about 1,000 BTU/hr-ft^2 of radiant heat. There are two continuous pilot burners with thermocouples for flame out detection and automatic ignition of the flare via a flame front generator. Platform flaring is performed to safely dispose of excess gas created by planned or upset conditions. The relief and flare system collects process vent and relief streams from hydrocarbon systems for safe, continuous burning at the flare. Fuel gas is used for pilot flame ignition and purge gas. The pilot gas and purge gas burned in the flare meets the total sulfur content limit of 50 ppmv. Emission factors for NO_x, CO, and ROC are taken from USEPA AP-42, Section 11.5 (May 1991). Factors for calculating PM are found in Santa Barbara APCD Flare Study Report, Table 3.1. Sulfur oxide emissions are based on mass balance calculations. The calculation methodology for the flare is:

$$ER = [(EF \times SCFPP \times HHV) \div 10^6]$$

where: ER = emission rate (lb/period)
EF = pollutant specific emission factor (lb/MMBtu)
SCFPP = gas flow rate per operating period (scf/period)
HHV = gas higher heating value (Btu/scf)

Platform Hidalgo is equipped with two flares: a high-pressure flare (FE-V24B) and a low-pressure flare (FE-V23). Each flare is monitored by a FCI Model LT81A mass flow meter. The calibrated flow range for the high-pressure flare is 0.021 - 31 MMscfd and for the low pressure flare is 0.027 - 2.5 MMscfd. The low flow, or minimum, detection limit is equivalent to 862 scfh for the high-pressure flare, which is less than the purge flow rate of 1,000 scfh (pilot flow rate is 140 scfh). The low flow, or minimum, detection limit is equivalent to 1,142 scfh for the low-pressure flare, which is greater that the purge flow rate of 540 scfh (pilot flow rate is 70 scfh). As such, there is no practical method for assessing flow rates between 540 and 1,142 scfh. Therefore, based on EPA and CARB's data reporting guidelines, a value of half the minimum detection limit is being assumed as "continuous" planned flaring. For the high-pressure flare, this value is 431 scfh. For the low-pressure flare, this value is 520 scfh. Since the purge flow rate is detected by the meter, this value is backed out of the half-minimum detect calculation. For the high-pressure flare, no continuous flaring is calculated. Flare gas volumes and related emissions are combined from the high and low-pressure flare and reported as being emitted from a single flare.

4.3 *Fugitive Hydrocarbon Emissions*: Emissions of reactive organic compounds from the valves and associated connections in gas service have been quantified using emission factors pursuant to APCD P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility Component Counts - Modified for Revised ROC Definition*). Specifically, the oil and gas service factors from the offshore platform category of Table 2 were used.

The component leak-path was counted consisted with P&P 6100.061. This leak-path count is not the same as the "component" count required by APCD Rule 331. On Platform Hidalgo there are 4,093 leak-paths in oil service and 3,738 in gas/light liquid service

The subject components are accessible and are safe to monitor. The calculation methodology for the fugitive emissions is:

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

where:

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

There are 725 gas service valves and 1,450 connections associated with these valves that are subject to an Enhanced I&M Program. Regular component leak-paths are normally assigned an I&M control efficiency of 80-percent. 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. PXP requested that the connections associated with the affected valves also be subject to the enhanced I&M program. The APCD evaluated the PXP's request and concurred that the emission factors used for Platform Hidalgo were developed in such a fashion that they differed substantively from those emission factors used for onshore applications. As such, the APCD has granted PXP's request to include the connections associated with the subject valves in the enhanced I&M program and that a new control efficiency of 82-percent be used for the connections.

4.4 Crew and Supply Vessels

Both crew and supply boats are used to support activities on Platform Hidalgo. Crew boats are only used for transporting work crews in the event bad weather or large numbers of workers make transportation by helicopter infeasible and are limited to eight trips per year.

Two supply boats are used to service Platform Hidalgo; the *M/V Victory Seahorse* and the *M/V Santa Cruz*. The *M/V Santa Cruz* is equipped with two 2,000 bhp Caterpillar 3516B low-NO_x main engines and has generator sets rated at 600 bhp and bow thrusters rated at 515 bhp.

The *M/V Victory Seahorse* main engines total 5,000 bhp and are controlled for NO_x emissions with turbocharging, 4° engine timing retard and intercooling. The *M/V Victory Seahorse* generator set is rated at 490 bhp and the bow thruster is rated at 515 bhp.

For permitting purposes, the permitted supply boat is represented by a "composite boat" consisting of the largest main, generator, and bow thruster engines of the boats, listed above, that have been designated by the permittee to service Platform Hidalgo. Because all three engine types are required to operate the supply boat, the boat is considered one emissions unit. The composite boat consists of 5,000 total bhp for the main engines, 600 total bhp for the generator sets and 515 total bhp bow thrusters. The auxiliary engines on the supply boats are not controlled for NO_x.

Crew boat engines are controlled for NO_x emissions through turbocharging, 4° engine timing retard and intercooling. The crew boat *Price Tide* was used for emissions calculations as the typical crew boat. This boat is equipped with three 510 bhp main IC engines. Auxiliary engines on this vessel include two-109 bhp generator engines. The auxiliary engines on the crew boats are not controlled for NO_x.

If controlled support vessels are not available, it may become necessary for the permittee to temporarily arrange for a spot-charter vessel. Spot-charter vessels are normally uncontrolled for NO_x. Spot-charter usage is limited to a maximum of 10-percent of the total support vessel usage in any one year (i.e., allowable usage is based on actual trips).

The permit is assessing NO_x emission liability based solely on a single emission factor (the cruise mode). For engines with the controls listed above, a full load NO_x emission factor of 8.4 g/bhp-hr (337 lb/1000 gallons) is used. Sulfur oxide emissions are based on mass balance calculations assuming 0.0015 weight percent sulfur diesel fuel. Other main engine vessel emission factors are taken from USEPA, AP-42 (Volume II). For the auxiliary and bow thruster engines, emission factors are taken from USEPA, AP-42 (Volume I). Uncontrolled main engine NO_x emission factors for spot-charter supply boat usage are assumed to be 14 g/bhp-hr (561 lb/1000 gallons).

The calculation methodology for the crew and supply boat main engine emissions is:

$$ER = [(EF \times EHP \times BSFC \times EL \times TM) \div (10^3)]$$

<u>where</u>: ER = emission rate (lbs per period)
EF = full load pollutant specific emission factor (lb/1000 gallons)

EHP =	engine max rated horsepower (bhp)
BSFC =	engine brake specific fuel consumption (gal/bhp-hr)
EL =	engine load factors (percent of max fuel consumption)
TM =	time in mode (hours/period)

The calculations for the auxiliary engines are similar, except that a 50-percent engine load factor for the generators is utilized. Compliance with the main engine controlled emission rates shall be assessed through emission source testing. Ongoing compliance is assessed through implementation of the most current version of the APCD-approved *Point Arguello Project Boat Monitoring and Reporting Plan.*

In addition, a permanently assigned emergency response boat (i.e., the *Clean Seas III*) is associated with Platform Hidalgo. The engines on this vessel are uncontrolled. The approximate total engine horsepower, including auxiliary engines, is 4,400 bhp. Emissions liability is assigned in a prorated fashion among the four OCS platforms that utilize the vessel off the Santa Barbara coast. Emission factors, calculations and compliance procedures are the same as for the spot-charter supply vessels discussed above. If used, other emergency response boat fuel usage (and resulting emissions) shall be assessed against this emissions category.

Platform Hidalgo also has three marine survival craft each equipped with two 62 bhp engines and one 36 bhp engine. Emissions are based on g/Bhp emission factors and a 200-hour per year operating limit.

4.5 Sulfur Treating/Gas Sweetening Unit

The purpose of the amine gas sweetening unit is to remove hydrogen sulfide from produced gas drawn off a side stream from the main gas compressor. This sweetened gas is sent to the flare relief system to provide the flare with purge/pilot gas. This gas is also burned in the gas turbine generators as fuel.

4.6 Tanks/Vessels/Sumps/Separators

Tanks: Platform Hidalgo has three diesel fuel storage tanks, two compressor lube oil tanks and one methanol storage tank. The diesel storage tanks service the various turbines and IC engines on the platform and are not controlled. Methanol is used on the platform, primarily to aide in the prevention of hydrates and for gas lift. Diesel tank and lube oil storage and handling emissions are very small and are assumed to be less than 0.10 tpy (200 lb/year). The detailed compliance calculations will be performed using the methods presented in USEPA AP-42, Chapter 12.

Vessels: Platform Hidalgo has many pressure vessels. All pressure vessels are connected to the platform's gas gathering system. All PSVs are connected to the flare relief system header. Emissions from pressure vessels are due to fugitive hydrocarbon leaks from valves and connections.

Sumps and Produced/Waste Water Tanks: Sumps and produced and wastewater tank emissions are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California,* January 1983). Produced and wastewater tanks are classified as being in secondary production and in light oil service. The calculation is:

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

<u>where</u>: ER = emission rate (lb/period)
EF = ROC emission factor (lb/ft^2-day)
SAREA = unit surface area (ft^2)
CE = control efficiency
HPP = operating hours per time period (hrs/period)

For open top tanks, no control efficiency is assigned. A leak free cover with a properly maintained PVRV is approximately 85-percent efficient and hookup to vapor recovery is assigned a 95-percent control efficiency.

Oil/Water Separators: Platform oil/water separators are a class of wastewater treatment equipment that processes known volumes of wastewater on a continuous basis to remove entrained oil. Emissions are calculated using the CARB uncontrolled emission factor of 381 lb_{ROC}/mm gallons of throughput. Control efficiencies for a cover and vapor recovery are the same as for sumps. The calculation is:

$$ER = (EF)(THRU)(1 - CE)(HPP)$$

where:

ER = emission rate (lb/period)
EF = ROC emission factor (lb/mm gallon throughput)
THRU = throughput (mm gallons)
CE = control efficiency
HPP = operating hours per time period

The emission factors are documented in the APCD's P&P 6100.060. For open top tanks, no control efficiency is assigned. A leak free cover with PVRVs is approximately 85-percent efficient and hookup to vapor recovery is assigned a 95-percent control efficiency.

4.7 Vapor Recovery Systems

The vapor recovery system collects vapors from various tanks and vessels and delivers them to the gas compression system.

4.8 Helicopters

Helicopters are used on Platform Hidalgo to transport crew from the Santa Maria airport. Sykorski Model 76A helicopters are used with typical round-trip times of 50 minutes in duration. Helicopter usage is shared with Platforms Hidalgo and Harvest. Emission factors, in units of "lb/hr", for different type of helicopters have been established for each operating mode based on the turbine engine used. These modes (idle, climb, cruise and decent) make up the total cycle time for each trip segment. For Platform Hidalgo, there are two identical trip segments (Santa Maria Airport to Platform Hidalgo and Platform Hidalgo to Santa Maria Airport). The emission rate per trip segment is calculated as:

$$ER = \Sigma_{mode} [EF_{mode} \times TIM]$$

where:

ER = Emission rate per trip segment (lb/segment)
EF = pollutant specific emission factor per mode (lb/engine-hr)
TIM = Time in Mode (hr)

From this data, a platform specific emission rate per trip segment is calculated. For platform Hidalgo, the one trip segment is simply doubled to obtain an emission rate per trip. Emission tracking is accomplished by reporting the number of trips per helicopter.

4.9 Other Emission Sources

The following is a brief discussion of other emission sources on Platform Hidalgo:

Pigging: Pipeline pigging operations occur on the platform. These consist of sending oil and gas pigs from pig launchers on Platform Hidalgo to Platform Hermosa. The pig launchers are depressurized to the flare relief system prior to pig loading process. There is a small amount of backpressure/emissions remaining in the launchers following depressurization that is emitted when the launch hatch is opened to the atmosphere. The remaining backpressure prior to opening the launchers to atmosphere cannot exceed 1 psig. The emission rate calculation per time period is:

$$ER = [V_1 \, x \, \rho \, x \, wt\,\% \, x \, EPP]$$

where:

ER = emission rate (lb/period)
V_1 = volume of vessel (ft^3)
ρ = density of vapor at actual conditions (lb/ft^3)
wt % = weight percent ROC-TOC
PP = pigging events per time period (events/period)

General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurs on Platform Hidalgo as part of normal daily operations. The usage includes cold solvent degreasing. Mass balance emission calculations are used assuming all unrecovered solvent used evaporates to the atmosphere.

Surface Coating: Surface coating operations typically include normal touch up activities. Entire platform painting programs are performed once every few years. Emissions are determined based on mass balance calculations assuming all unrecovered 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 electric. 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.

4.10 BACT

Except as described below, none of the emission units at Platform Hidalgo are subject to best available control technology (BACT), NSPS or NESHAP provisions.
Pursuant to Rule 331.E.1.b, all leaks from critical components are required to be replaced with BACT in accordance with the APCD's NSR rule.

4.11 CEMS/Process Monitoring/CAM

4.11.1 *CEMS*: There are no in-stack continuous emission monitoring systems used on Platform Hidalgo to measure criteria pollutant emissions. However, a hydrogen sulfide analyzer is required to assess compliance with the fuel gas sulfur limits. This analyzer is classified as a CEM by the APCD and is subject to the APCD's CEM Protocol document (dated October 22, 1992 and any subsequent updates). This data does not have to be telemetered to the APCD. For most platform operations, process monitors (e.g., fuel meters) provide adequate data to assess compliance. See Section 4.12.

4.11.2 Process Monitoring: In many instances, ongoing compliance beyond a single (snap shot) source test is assessed by the use of process monitoring systems. Examples of these monitors include: engine hour meters, fuel usage meters, water injection mass flow meters, and flare gas flow meters. 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 are required to be operated, calibrated and maintained in good working order:

- → Turbine Generator Fuel Gas Meters
- → Turbine Generator Diesel Fuel Meters
- → Turbine Generator Water Injection Meters
- → Turbine Generator Water/Fuel Controllers
- → Turbine Generator Fuel Gas PLC
- → Crane Engine Hour Meters
- → Stand-by Generator Hour Meter
- → Firewater Pump Hour Meter
- → Supply Vessel Diesel Fuel Meters
- → Crew Vessel Diesel Fuel Meters
- → The Flare Header Flow Meters

Calibration and maintenance shall be done according to the most current version of the APCD-approved *Process Monitor Calibration and Maintenance Plan.* This Plan takes into consideration manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment is utilized.

4.11.3 CAM: 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. Turbines G-92 and G-93 satisfy the criterion listed in items (1) and (2) above and are therefore subject to this rule. For units subject to the rule, a CAM Plan is required that identifies one or more operational parameters to be monitored and serve as compliance indicators for emission limits.

The subject turbines are equipped with water injection as the primary emission controls. The permit requires a minimum water to fuel ratio of 0.80 and therefore, the water to fuel ratio was chosen as the CAM parameter to be monitored. PXP submitted a revised Turbine ADGS Quality Assurance Plan that includes a CAM Plan detailing monitoring procedures, averaging period, and alarming procedures of the water to fuel ratio data. A minimum of one data point every 24-hours is required for these turbines under the CAM regulations.

4.12 Source Testing/Sampling

Source testing and sampling is required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. The permittee is required to follow the APCD *Source Test Procedures Manual* (May 24, 1990 and all updates). The following emission units are required to be source tested.

- Gas Turbines (G-91 through G-94)
- West Crane Engine (G-360)
- East Crane Engine (G-361)
- Supply Boat Main Engines

At a minimum, the following process streams are required to be sampled and analyzed annually. Refer to Table 4.1 for specific source test requirements. Duplicate samples are required.

→ Produced Gas: Sample taken at production separator outlet. Analysis for: HHV, total sulfur, hydrogen sulfide, composition.

→ Fuel Gas: Sample taken at fuel gas header. Analysis for: HHV, total sulfur, hydrogen sulfide, composition.

→ Produced Oil: Sample taken at outlet from production separator. Analysis for: API gravity; true vapor pressure (per Rule 325 methods).

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 permittee is required to amend their source test plan to address the sampling and analytical methods required to obtain the process stream data stated above.

TABLE 4.1
SOURCE TEST REQUIREMENTS

Emission Points	Pollutants/ Parameters	Test Methods
- Crane Engines - Supply Boat Main Engines - Turbines	NO_x (ppmv, lb/hr)	CARB 1-100 or USEPA 7E
	CO (ppmv, lb/hr)	CARB 1-100 or USEPA 10
	ROC (ppmv, lb/hr)	USEPA 18
	Fuel Flow Rate	meter
	Fuel High Heating Value	ASTM
	Total Sulfur Content	ASTM

Site Specific Requirements

a. All annual turbine emissions tests are to consist of three 40-minute runs or other duration approved by the APCD. Crane engine tests are to consist of three 20-minute runs. Both crane engines and one turbine are to be tested at maximum safe load. The remaining three turbines are to be tested at "historical" loads. Maximum loaded turbine will sequentially rotate to each of the four turbines in subsequent annual tests. Supply boat main engines to be tested at cruise load. Subsequent testing may be required if loads are not achieved. Additional turbine test requirements, including exemptions from testing, are listed in Section 9 of this permit.
b. The specific project supply boat to be tested shall be determined by the APCD.
c. USEPA methods 1-4 to be used to determine O_2, dry MW, moisture content, CO_2, and stack flow rate. Alternatively, USEPA 19 may be used to determine stack flow rate.
d. SO_x emissions to be determined by mass balance calculation.
e. The main engines from one supply boat shall be tested annually. Crane engines shall be tested biennially.
f. Procedures to obtain the required operating loads shall be clearly defined in the source test plan.

5.0 Emissions

5.1 General

Emissions calculations are divided into "permitted" and "exempt" categories. Permit exempt equipment is determined by APCD Rule 202. The permitted emissions for each emissions unit is based on the equipment's potential-to-emit (as defined by Rule 102). The following tables detail the facility emissions:

- Table 5.1 contains the operating equipment description, the equipment emission factors and the hourly, daily, quarterly and annual emissions for each equipment item.
- Table 5.2 summarizes the permitted emissions for each equipment group.
- Section 5.3 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301.
- Table 5.4 provides the estimated emissions from permit exempt equipment and also serves as the Part 70 list of insignificant emission.
- Table 5.5 provides the net emissions increase calculation for the facility and the stationary source.

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 may be found in Section 4 and Attachment 10.1. Table 5.1-1 provides the basic operating characteristics. Table 5.1-2 provides the specific emission factors. Tables 5.1-3 and 5.1-4 shows the permitted short-term and permitted long-term emissions for each unit or operation. All emission limits from Platform Hidalgo are federally-enforceable per 40 CFR Part 55 {*OCS Air Regulation*}.

---

[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

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 5.1-1 for each emission unit are assumed. Table 5.2 shows the total permitted emissions for the facility.

Hourly and Daily Scenarios:

- East and west crane engines
- Emergency generator and firewater pump
- Turbines (diesel fired)
- Flare purge and pilot
- Planned continuous flaring
- Spot charter crew and supply boat
- Generator engines on crew and supply boat provide half of maximum engine rating
- Bow thruster on supply boat does not operate during peak hour
- Fugitive components
- Oil pig launcher (one only)
- Gas pig launcher (one only)
- All sumps
- All oil/water separators
- Solvent usage
- Degreaser usage
- Turbine starter engines are not in worst-case short-term scenarios.

Quarterly and Annual Scenario:

- East and west crane engines
  Emergency generator and firewater pump
- Turbines (diesel fired for maximum allowable hours and remaining hours on fuel gas fire)
- Flare purge and pilot
- Planned continuous flaring
- Planned intermittent (other) flaring
- Unplanned flaring
- Fugitive components
- Controlled crew and supply boats
- Uncontrolled crew and supply boats
- Generator engines on crew and supply boat provide half of maximum engine rating
- Bow thruster on supply boat
- Emergency response boat
- Oil pig launcher (one only)
- Gas pig launcher (one only)
- All sumps
- All oil/water separators
- Solvent usage
- Degreaser usage
- Turbine starter engines are not in worst-case long-term scenarios

5.4 Part 70: Federal Potential to Emit for the Facility

Table 5.3 lists the federal Part 70 potential to emit. Being subject to the OCS Air Regulation, all project emissions, except fugitive emissions, are counted in the federal definition of potential to emit. However, fugitives are counted in the Federal PTE if the facility is subject to any applicable NSPS or NESHAP requirement.

5.5 Exempt Emission Sources/Part 70 Insignificant Emissions

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Under the APCD's Part 70 regulation, equipment/activities that are exempt under Rule 202 are considered insignificant units emissions. In addition, *insignificant activities* 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 stationary source are listed in Table 5.0. This facility's contribution to the stationary source's NEI since November 15, 1990 (the day the federal Clean Air Act Amendments was adopted in 1990) are listed in Table 5.5. These values are based on the following NSR permit actions since December 5, 1991:

***ATC/PTO 9947*:** Increased the carbon monoxide (CO) emission factor for the three dual-fuel turbines when they are fired on natural gas. This resulted in a CO NEI of 2.46 lbs/hour, 59.04 lbs/day, 2.06 tons/qtr and 7.44 tons/year.

***ATC/PTO 10260*:** Increased the sulfur content of the gas flared on Platform Hidalgo from 1.70-percent sulfur to 2.07-percent sulfur. This resulted in a SO_x NEI of 0.02 lbs/hour, 0.47 lbs/day, 1.00 tons/qtr and 4.00 tons/year.

***ATC/PTO 10260-01*:** Increased the sulfur content of the planned (continuous) gas flared on Platform Hidalgo from 2.07-percent sulfur to 3.20-percent sulfur. This resulted in a SO_x NEI of 0.06 lbs/hour, 1.42 lbs/day, 0.06 tons/qtr and 0.26 tons/year.

***ATC 10331/PTO 10331*:** This permit authorized the sulfur content of the purge/pilot gas flared on the platform to be increased from 50 ppmv sulfur to 165 ppmv sulfur, which is the sulfur content of propane that meets the specifications of the Gas Processors Association. This change will allow propane to be used as purge/pilot gas when produced gas that meets the permitted sulfur limit is unavailable. This increase results in a SO_x emission increase of 1.04 lbs/day. Issued 11/27/00.

***ATC/PTO 11082*:** This permit authorized the increase in the turbine starter engine run time for each turbine starter engine. This modification resulted in the following NO_x, ROC, CO, SO_x, PM and PM_{10} lb/day emission increases, respectively: 14.48, 0.96, 5.28, 1.01, 1.04 and 1.01.

***ATC/PTO 11662*:** This permit authorized an increase in the number of pigging events and pigging emissions. This modification resulted in the following ROC emission increase: 0.28 lb/day ROC.

Table 5.0
Stationary Source Net Emission Increase Since 1990 (FNEI-90)

Facility	NO_x	ROC	CO	SO_x	TSP	PM_{10}
Gaviota Plant						
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 5.1-1
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Operating Equipment Description

		Device Specifications				Usage Data			Maximum Operating Schedule				
Equipment Category	**Description**	**Fuel**	**% S**	**Size**	**Units**	**Capacity**	**Units**	**Load**	**hr**	**day**	**qtr**	**year**	**References**
Combustion - Engines	West Crane	D2	0.0015	475	bhp	6,812	Btu/bhp-hr	--	1.0	24	800	3,200	A
	East Crane	D2	0.0015	475	bhp	6,812	Btu/bhp-hr	--	1.0	24	800	3,200	
	Emergency Generator	D2	0.0015	1,350	bhp	--	--	--	1.0	2.0	200	200	
	Emergency Generator	D2	0.0015	1,250	bhp	--	--	--	1.0	2.0	200	200	
	Emergency Firewater Pump	D2	0.0015	517	bhp	--	--	--	1.0	2.0	200	200	
Combustion - HP & LP Flare	Purge and Pilot	PG	0.0165	1,750	scfh	2.686	MMBtu/hr	--	1.0	24	2,190	8,760	B
	Planned - continuous	SG	3.200	31	scfh	0.272	MMscf/yr	--	1.0	24	0.25	1	
	Planned - other	SG	2.070	3,800	MMBtu/hr	2.470	MMscf/yr	--	--	--	0.25	1	
	Unplanned	SG	2.070	3,800	MMBtu/hr	10.045	MMscf/yr	--	--	--	0.25	1	
Fugitive Components - Oil	Controlled	--	--	4,093	comp-lp	--	--	--	1.0	24	2,190	8,760	C
	Unsafe	--	--	0	comp-lp	--	--	--	1.0	24	2,190	8,760	
Fugitive Components - Gas	Valves/Connections	--	--	3,738	comp-lp	--	--	--	1.0	24	2,190	8,760	C
	Valves/Cnectns: Unsafe	--	--	0	comp-lp	--	--	--	1.0	24	2,190	8,760	
	Valves: Monthly	--	--	725	comp-lp	--	--	--	1.0	24	2,190	8,760	
	Valves Cnectns: Monthly	--	--	1,450	comp-lp	--	--	--	1.0	24	2,190	8,760	
	Valve Cnectns: Unsafe	--	--	0	comp-lp	--	--	--	1.0	24	2,190	8,760	
Supply Boat	Main Engines - con	D2	0.0015	5,000	bhp-total	0.055	gal/bhp-hr	0.65	1.0	11	459	1,837	D
	Main Engines - uncon	D2	0.0015	5,000	bhp-total	0.055	gal/bhp-hr	0.65	1.0	11	46	184	
	Generator Engines	D2	0.0015	600	bhp-total	0.055	gal/bhp-hr	0.50	1.0	11	459	1,837	
	Bow Thruster	D2	0.0015	515	bhp	0.055	gal/bhp-hr	1.00	1.0	2	78	312	
	Emergency Response	D2	0.0015	4,400	bhp-total	0.055	gal/bhp-hr	0.65	--	--	32	127	
	Survival Craft	D2	0.0015	160	bhp-total	--	--	0.65	--	--	50	200	
Crew Boat	Main Engines - con	D2	0.0015	1,530	bhp-total	0.055	gal/bhp-hr	0.85	1.0	11	22	88	E
	Main Engines - uncon	D2	0.0015	1,530	bhp-total	0.055	gal/bhp-hr	0.85	1.0	11	11	11	
	Generator Engines	D2	0.0015	218	bhp-total	0.055	gal/bhp-hr	0.50	1.0	11	22	88	
Pigging Equipment	Oil Pig Launcher	--	--	35.0	cf	1	psig	--	1.0	4	91	365	F
	Gas Pig Launcher	--	--	16.0	cf	1	psig	--	1.0	4	91	365	

Table 5.1-2
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Equipment Emission Factors

		Emission Factors							
Equipment Category	**Description**	**NOx**	**ROC**	**CO**	**SOx**	**PM**	**PM10**	**Units**	**References**
Combustion - Engines	West Crane	2.565	0.30	0.95	0.002	0.31	0.30	lb/MMBtu	A
	East Crane	2.565	0.30	0.95	0.002	0.31	0.30	lb/MMBtu	
	Emergency Generator	14.06	1.12	3.03	0.002	0.98	0.98	g/bhp-hr	
	Emergency Generator	14.06	1.12	3.03	0.002	0.98	0.98	g/bhp-hr	
	Emergency Firewater Pum	14.06	1.12	3.03	0.002	0.98	0.98	g/bhp-hr	
Combustion - HP & LP Flare	Purge and Pilot	0.068	0.12	0.37	0.023	0.02	0.02	lb/MMBtu	B
	Planned - continuous	0.068	0.12	0.37	3.523	0.02	0.02	lb/MMBtu	
	Planned - other	0.068	0.12	0.37	2.279	0.02	0.02	lb/MMBtu	
	Unplanned	0.068	0.12	0.37	2.279	0.02	0.02	lb/MMBtu	
Fugitive Components - Oil	Controlled	--	0.0009	--	--	--	--	lb/day-clp	C
	Unsafe	--	0.0044	--	--	--	--	lb/day-clp	
Fugitive Components - Gas	Valves/Connections	--	0.0147	--	--	--	--	lb/day-clp	C
	Valves/Cnectns: Unsafe	--	0.0736	--	--	--	--	lb/day-clp	
	Valves: Monthly	--	0.0118	--	--	--	--	lb/day-clp	
	Valves Cnectns: Monthly	--	0.0132	--	--	--	--	lb/day-clp	
	Valve Cnectns: Unsafe	--	0.0736	--	--	--	--	lb/day-clp	
Supply Boat	Main Engines - con	337	16.80	78.30	0.21	33.00	31.68	lb/1000 gal	D
	Main Engines - uncon	561	16.80	78.30	0.21	33.00	31.68	lb/1000 gal	
	Generator Engines	600	48.98	129.26	0.21	42.18	40.49	lb/1000 gal	
	Bow Thruster	600	48.98	129.26	0.21	42.18	40.49	lb/1000 gal	
	Emergency Response	561	16.80	78.30	0.21	33.00	31.68	lb/1000 gal	
	Survival Craft	1.08	90.40	212.00	0.27	24.00	24.00	g/bhp-hr	
Crew Boat	Main Engines - con	337	42.28	99.70	0.21	33.00	31.68	lb/1000 gal	E
	Main Engines - uncon	561	42.28	99.70	0.21	33.00	31.68	lb/1000 gal	
	Generator Engines	600	48.98	129.26	0.21	42.18	40.49	lb/1000 gal	
Pigging Equipment	Oil Pig Launcher	--	0.0026	--	--	--	--	lb/acf-evnt	F
	Gas Pig Launcher	--	0.0001	--	--	--	--	lb/acf-evnt	

Table 5.1-2
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Equipment Emission Factors

		Emission Factors							
Equipment Category	**Description**	**NOx**	**ROC**	**CO**	**SOx**	**PM**	**PM10**	**Units**	**References**
Sumps/Tanks/Separators	Prod Water Surge Tank	--	0.019	--	--	--	--	lb/ft2-day	G
	Disposal Pile	--	0.019	--	--	--	--	lb/ft2-day	
	Sump Tank	--	0.003	--	--	--	--	lb/ft2-day	
	Sump Deck Tank	--	0.019	--	--	--	--	lb/ft2-day	
	Cutting Dewater Shaker	--	0.019	--	--	--	--	lb/ft2-day	
	Air Flotation Cell	--	19.05	--	--	--	--	lb/mmgal thru	
	CPI Separator	--	19.05	--	--	--	--	lb/mmgal thru	
	CPI Separator	--	19.05	--	--	--	--	lb/mmgal thru	
	Oily Water Tank	--	0.003	--	--	--	--	lb/ft2-day	
Solvent Usage	Cleaning/degreasing	--	various	--	--	--	--	lb/gal	H
Combustion-Turbines	G-91 (PG)	6.89	0.72	4.54	0.28	0.10	0.10	lb/hr	I
	G-91 (D2)	6.90	2.46	8.86	0.00	1.99	1.99	lb/hr	
	G-92 (PG)	6.89	0.72	4.54	0.28	0.10	0.10	lb/hr	
	G-92 (D2)	6.90	2.46	8.86	0.00	1.99	1.99	lb/hr	
	G-93 (PG)	6.89	0.72	4.54	0.28	0.10	0.10	lb/hr	
	G-93 (D2)	6.90	2.46	8.86	0.00	1.99	1.99	lb/hr	
	G-94 (PG)	3.70	0.36	3.72	0.31	0.11	0.11	lb/hr	
	G-94 (D2)	0.00	0.00	0.00	0.00	0.00	0.00	lb/hr	
Combustion-Starter Engines	6-91 S/N 03203327	4.41	0.30	0.95	0.30	0.31	0.30	lb/MMBTU	J
	6-92 S/N 03203335	4.41	0.30	0.95	0.30	0.31	0.30	lb/MMBTU	
	6-93 S/N 03203326	4.41	0.30	0.95	0.30	0.31	0.30	lb/MMBTU	
	6-94 S/N 03203337	4.41	0.30	0.95	0.30	0.31	0.30	lb/MMBTU	

Table 5.1-3
Point Arguello Project Platform Hidalgo:Permit to Operate No. 9105
Hourly and Daily Emissions

Equipment Category	Description	NOx lb/hr	NOx lb/day	ROC lb/hr	ROC lb/day	CO lb/hr	CO lb/day	SOx lb/hr	SOx lb/day	PM lb/hr	PM lb/day	PM10 lb/hr	PM10 lb/day
Combustion - Engines	West Crane	8.80	211.13	1.03	24.69	3.26	78.20	0.01	0.13	1.06	25.52	1.02	24.50
	East Crane	8.80	211.13	1.03	24.69	3.26	78.20	0.01	0.13	1.06	25.52	1.02	24.50
	Emergency Generator	--	77.42	--	6.17	--	16.69	--	0.01	--	5.40	--	5.40
	Emergency Firewater Pum	--	32.02	--	2.55	--	6.90	--	0.00	--	2.23	--	2.23
Combustion - HP & LP Flare	Purge and Pilot	0.18	4.38	0.32	7.76	0.99	23.85	0.06	1.50	0.05	1.29	0.05	1.29
	Planned - continuous	0.00	0.08	0.01	0.14	0.02	0.42	0.17	4.02	0.00	0.02	0.00	0.02
	Planned - other	--	--	--	--	--	--	--	--	--	--	--	--
	Unplanned	--	--	--	--	--	--	--	--	--	--	--	--
Fugitive Components - Oil	Controlled	--	--	0.15	3.59	--	--	--	--	--	--	--	--
	Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
Fugitive Components - Gas	Valves/Connections	--	--	2.29	55.02	--	--	--	--	--	--	--	--
	Valves/Cnectns: Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
	Valves: Monthly	--	--	0.36	8.54	--	--	--	--	--	--	--	--
	Valves Cnectns: Monthly	--	--	0.80	19.21	--	--	--	--	--	--	--	--
	Valve Cnectns: Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
Supply Boat	Main Engines - con	60.19	662.0	3.00	33.03	14.00	154.0	0.04	0.4	5.90	64.9	5.66	62.3
	Main Engines - uncon	100.31	1,103.4	3.00	33.03	14.00	154.0	0.04	0.4	5.90	64.9	5.66	62.3
	Generator Engines	9.90	108.9	0.81	8.89	2.13	23.5	0.00	0.0	0.70	7.7	0.67	7.3
	Bow Thruster	17.00	34.0	1.39	2.77	3.66	7.3	0.01	0.0	1.19	2.4	1.15	2.3
	Emergency Response	--	--	--	--	--	--	--	--	--	--	--	--
Crew Boat	Main Engines - con	24.08	264.9	3.02	33.26	7.13	78.4	0.02	0.2	2.36	26.0	2.27	24.9
	Main Engines - uncon	40.14	441.5	3.02	33.26	7.13	78.4	0.02	0.2	2.36	26.0	2.27	24.9
	Generator Engines	3.60	39.6	0.29	3.23	0.77	8.5	0.00	0.0	0.25	2.8	0.24	2.7
Pigging Equipment	Oil Pig Launcher	--	--	0.09	0.36	--	--	--	--	--	--	--	--
	Gas Pig Launcher	--	--	0.00	0.01	--	--	--	--	--	--	--	--

Note: 0.00 indicates emissions are less than 0.01. "--" indicates that emissions were not calculated for this category.

Table 5.1-3
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Hourly and Daily Emissions

Equipment Category	Description	NOx		ROC		CO		SOx		PM		PM10	
		lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day
Sumps/Tanks/Separators	Prod Water Surge Tk	--	--	0.03	0.7	--	--	--	--	--	--	--	--
	Disposal Pile	--	--	0.01	0.2	--	--	--	--	--	--	--	--
	Sump Tank	--	--	0.01	0.3	--	--	--	--	--	--	--	--
	Sump Deck Tank	--	--	0.06	1.4	--	--	--	--	--	--	--	--
	Cutting Dewater Shaker	--	--	0.04	0.9	--	--	--	--	--	--	--	--
	Air Flotation Cell	--	--	0.86	20.6	--	--	--	--	--	--	--	--
	CPI Separator	--	--	0.43	10.3	--	--	--	--	--	--	--	--
	CPI Separator	--	--	0.43	10.3	--	--	--	--	--	--	--	--
	Oily Water Tank	--	--	0.01	0.14	--	--	--	--	--	--	--	--
Solvent Usage	Cleaning/degreasing	--	--	8.59	68.7	--	--	--	--	--	--	--	--
Combustion-Turbines	G-91 (PG)	6.89	165.42	0.72	17.28	4.54	109.06	0.28	6.72	0.10	2.42	0.10	2.42
	G-91 (D2)	6.90	165.68	2.46	59.11	8.86	212.55	0.00	0.10	1.99	47.71	1.99	47.71
	G-92 (PG)	6.89	165.42	0.72	17.28	4.54	109.06	0.28	6.72	0.10	2.42	0.10	2.42
	G-92 (D2)	6.90	165.68	2.46	59.11	8.86	212.55	0.00	0.10	1.99	47.71	1.99	47.71
	G-93 (PG)	6.89	165.42	0.72	17.28	4.54	109.06	0.28	6.72	0.10	2.42	0.10	2.42
	G-93 (D2)	6.90	165.68	2.46	59.11	8.86	212.55	0.00	0.10	1.99	47.71	1.99	47.71
	G-94 (PG)	3.70	88.80	0.36	8.64	3.72	89.25	0.31	7.44	0.11	2.68	0.11	2.68
	G-94 (D2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combustion-Starter Engines	6-91 S/N 03203327	7.24	7.24	0.49	0.49	1.56	1.56	0.49	0.49	0.51	0.51	0.49	0.49
	6-92 S/N 03203335	7.24	7.24	0.49	0.49	1.56	1.56	0.49	0.49	0.51	0.51	0.49	0.49
	6-93 S/N 03203326	7.24	7.24	0.49	0.49	1.56	1.56	0.49	0.49	0.51	0.51	0.49	0.49
	6-94 S/N 03203337	7.24	7.24	0.49	0.49	1.56	1.56	0.49	0.49	0.51	0.51	0.49	0.49

Note: 0.00 indicates emissions are less than 0.01. "--" indicates that emissions were not calculated for this category.

Table 5.1-4
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Quarterly and Annual Emissions

Equipment Category	Description	NOx TPQ	NOx TPY	ROC TPQ	ROC TPY	CO TPQ	CO TPY	SOx TPQ	SOx TPY	PM TPQ	PM TPY	PM10 TPQ	PM10 TPY
Combustion - Engines	West Crane	3.52	14.08	0.41	1.65	1.30	5.21	0.00	0.01	0.43	1.70	0.41	1.63
	East Crane	3.52	14.08	0.41	1.65	1.30	5.21	0.00	0.01	0.43	1.70	0.41	1.63
	Emergency Generator	--	4.18	--	0.33	--	0.90	--	0.00	--	0.29	--	0.29
	Emergency Generator	--	3.87	--	0.31	--	0.83	--	0.00	--	0.27	--	0.27
	Emergency Firewater Pumj	--	1.60	--	0.13	--	0.35	--	0.00	--	0.11	--	0.11
Combustion - HP & LP Flare	Purge and Pilot	0.20	0.80	0.35	1.42	1.09	4.35	0.07	0.27	0.06	0.24	0.06	0.24
	Planned - continuous	0.00	0.01	0.01	0.03	0.02	0.08	0.18	0.73	0.00	0.00	0.00	0.00
	Planned - other	0.03	0.13	0.06	0.23	0.18	0.70	1.08	4.32	0.01	0.04	0.01	0.04
	Unplanned	0.13	0.52	0.23	0.93	0.71	2.85	4.39	17.57	0.04	0.15	0.04	0.15
Fugitive Components - Oil	Controlled	--	--	0.16	0.66	--	--	--	--	--	--	--	--
	Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
Fugitive Components - Gas	Valves/Connections	--	--	2.51	10.04	--	--	--	--	--	--	--	--
	Valves/Cnectns: Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
	Valves: Monthly	--	--	0.39	1.56	--	--	--	--	--	--	--	--
	Valves Cnectns: Monthly	--	--	0.88	3.51	--	--	--	--	--	--	--	--
	Valve Cnectns: Unsafe	--	--	0.00	0.00	--	--	--	--	--	--	--	--
Supply Boat	Main Engines - con	13.81	55.28	0.69	2.76	3.21	12.86	0.01	0.03	1.35	5.42	1.30	5.20
	Main Engines - uncon	2.30	9.21	0.07	0.28	0.32	1.29	0.00	0.00	0.14	0.54	0.13	0.52
	Generator Engines	2.27	9.09	0.19	0.74	0.49	1.96	0.00	0.00	0.16	0.64	0.15	0.61
	Bow Thruster	0.66	2.65	0.05	0.22	0.14	0.57	0.00	0.00	0.05	0.19	0.04	0.18
	Emergency Response	1.40	5.61	0.04	0.17	0.20	0.78	0.00	0.00	0.08	0.33	0.08	0.32
	Survival Craft	0.01	0.02	0.52	2.07	1.22	4.86	0.00	0.01	0.14	0.55	0.14	0.55
Crew Boat	Main Engines - con	0.26	1.06	0.03	0.13	0.08	0.31	0.00	0.00	0.03	0.10	0.02	0.10
	Main Engines - uncon	0.22	0.22	0.02	0.02	0.04	0.04	0.00	0.00	0.01	0.01	0.01	0.01
	Generator Engines	0.04	0.16	0.00	0.01	0.01	0.03	0.00	0.00	0.00	0.01	0.00	0.01
Pigging Equipment	Oil Pig Launcher	--	--	0.00	0.02	--	--	--	--	--	--	--	--
	Gas Pig Launcher	--	--	0.00	0.00	--	--	--	--	--	--	--	--

Note: 0.00 indicates emissions are less than 0.01. "--" indicates that emissions were not calculated for this category.

Table 5.1-4
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Quarterly and Annual Emissions

		NOx		ROC		CO		SOx		PM		PM10	
Equipment Category	**Description**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**	**TPQ**	**TPY**
Sumps/Tanks/Separators	Prod Water Surge Tk	--	--	0.03	0.12	--	--	--	--	--	--	--	--
	Disposal Pile	--	--	0.01	0.04	--	--	--	--	--	--	--	--
	Sump Tank	--	--	0.00	0.01	--	--	--	--	--	--	--	--
	Sump Deck Tank	--	--	0.06	0.25	--	--	--	--	--	--	--	--
	Cutting Dewater Shaker	--	--	0.04	0.16	--	--	--	--	--	--	--	--
	Air Flotation Cell	--	--	0.94	3.75	--	--	--	--	--	--	--	--
	CPI Separator	--	--	0.47	1.88	--	--	--	--	--	--	--	--
	CPI Separator	--	--	0.47	1.88	--	--	--	--	--	--	--	--
	Oil/Water CPI Separator	--	--	0.01	0.03	--	--	--	--	--	--	--	--
Solvent Usage	Cleaning/degreasing	--	--	3.14	12.54	--	--	--	--	--	--	--	--
Combustion-Turbines	G-91 (PG)	2.07	2.07	0.22	0.22	1.36	1.36	0.08	0.08	0.03	0.03	0.03	0.03
	G-91 (D2)	2.07	2.07	0.74	0.74	2.66	2.66	0.00	0.00	0.60	0.60	0.60	0.60
	G-92 (PG)	7.55	30.19	0.79	3.15	4.98	19.90	0.31	1.23	0.11	0.44	0.11	0.44
	G-92 (D2)	3.02	6.04	1.08	2.16	3.87	7.75	0.00	0.00	0.87	1.74	0.87	1.74
	G-93 (PG)	7.55	30.19	0.79	3.15	4.98	19.90	0.31	1.23	0.11	0.44	0.11	0.44
	G-93 (D2)	3.02	6.04	1.08	2.16	3.87	7.75	0.00	0.00	0.87	1.74	0.87	1.74
	G-94 (PG)	4.05	16.21	0.39	1.58	4.07	16.29	0.34	1.36	0.12	0.49	0.12	0.49
	G-94 (D2)	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Combustion-Starter Engines	6-91 S/N 03203327	0.72	0.72	0.05	0.05	0.16	0.16	0.05	0.05	0.05	0.05	0.05	0.05
	6-92 S/N 03203335	0.72	.0.72	0.05	0.05	0.16	0.16	0.05	0.05	0.05	0.05	0.05	0.05
	6-93 S/N 03203326	0.72	0.72	0.05	0.05	0.16	0.16	0.05	0.05	0.05	0.05	0.05	0.05
	6-94 S/N 03203337	0.72	0.72	0.05	0.05	0.16	0.16	0.05	0.05	0.05	0.05	0.05	0.05

Table 5.2
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Total Permitted Facility Emissions

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	46.56	4.03	12.76	1.97	4.16	4.00
Combustion-Turbines	20.71	7.39	26.57	0.01	5.96	5.96
Combustion - HP & LP Flare	0.19	0.33	1.01	0.23	0.05	0.05
Fugitive Components	--	3.60	--	--	--	--
Supply Boat	127.21	5.20	19.79	0.05	7.79	7.48
Emergency Response	--	--	--	--	--	--
Crew Boat	43.74	3.32	7.91	0.02	2.61	2.51
Pigging	--	0.09	--	--	--	--
Sumps/Tanks/Separators	--	1.86	--	--	--	--
Solvent Usage	--	8.59	--	--	--	--
	238.40	34.41	68.03	2.27	20.58	20.00

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	560.67	60.08	186.22	2.22	60.70	58.58
Combustion-Turbines	497.05	177.34	637.66	0.30	143.14	143.14
Combustion - HP & LP Flare	4.46	7.90	24.28	5.52	1.31	1.31
Fugitive Components	--	86.35	--	--	--	--
Supply Boat	1,246.30	44.70	184.74	0.47	74.93	71.93
Emergency Response	--	--	--	--	--	--
Crew Boat	481.10	36.49	86.97	0.18	28.75	27.60
Pigging	--	0.37	--	--	--	--
Sumps/Tanks/Separators	--	44.75	--	--	--	--
Solvent Usage	--	68.71	--	--	--	--
	2,789.58	526.69	1,119.87	8.69	308.82	302.55

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	9.93	1.02	3.23	0.20	1.05	1.01
Combustion-Turbines	21.23	4.24	20.45	0.71	2.59	2.59
Combustion - HP & LP Flare	0.37	0.65	2.00	5.72	0.11	0.11
Fugitive Components	--	3.94	--	--	--	--
Supply Boat	19.05	1.00	4.17	0.01	1.70	1.63
Emergency Response	1.40	0.04	0.20	0.00	0.08	0.08
Survival Craft	0.01	0.52	1.22	0.00	0.14	0.14
Crew Boat	0.53	0.05	0.13	0.00	0.04	0.04
Pigging	--	0.00	--	--	--	--
Sumps/Tanks/Separators	--	2.03	--	--	--	--
Solvent Usage	--	3.14	--	--	--	--
	52.51	16.62	31.38	6.65	5.71	5.60

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	40.70	4.26	13.13	0.21	4.28	4.13
Combustion-Turbines	78.68	11.67	50.72	3.33	5.27	5.27
Combustion - HP & LP Flare	1.47	2.60	7.98	22.90	0.43	0.43
Fugitive Components	--	15.76	--	--	--	--
Supply Boat	76.24	3.99	16.67	0.04	6.79	6.51
Emergency Response	5.61	0.17	0.78	0.00	0.33	0.32
Survival Craft	0.02	2.07	4.86	0.01	0.55	0.55
Crew Boat	1.44	0.16	0.39	0.00	0.13	0.12
Pigging	--	0.02	--	--	--	--
Sumps/Tanks/Separators	--	8.12	--	--	--	--
Solvent Usage	--	12.54	--	--	--	--
	204.15	61.36	94.54	26.49	17.77	17.34

Table 5.3
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Federal Potential to Emit

A. PEAK HOURLY (lb/hr)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	46.56	4.03	12.76	1.97	4.16	4.00
Combustion-Turbines	20.71	7.39	26.57	2.44	5.96	5.96
Combustion - HP & LP Flare	0.19	0.33	1.01	0.19	0.05	0.05
Supply Boat	127.21	5.20	19.79	9.13	7.79	7.48
Emergency Response	–	–	–	–	–	–
Crew Boat	43.74	3.32	7.91	3.17	2.61	2.51
Pigging	–	0.09	–	–	–	–
Sumps/Tanks/Separators	–	1.86	–	–	–	–
Solvent Usage	–	8.59	–	–	–	–
Exempt Emissions	1.32	1.50	1.16	0.15	0.12	0.11
	239.72	32.31	69.19	17.04	20.70	20.12

B. PEAK DAILY (lb/day)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	560.67	60.08	186.22	2.22	60.70	58.58
Combustion-Turbines	497.05	177.34	637.66	58.46	143.14	143.14
Combustion - HP & LP Flare	4.46	7.90	24.28	4.48	1.31	1.31
Supply Boat	1,246.30	44.70	184.74	90.05	74.93	71.93
Emergency Response	–	–	–	–	–	–
Crew Boat	481.10	36.49	86.97	34.83	28.75	27.60
Pigging	–	0.09	–	–	–	–
Sumps/Tanks/Separators	–	44.75	–	–	–	–
Solvent Usage	–	68.71	–	–	–	–
Exempt Emissions	31.67	36.00	27.78	3.62	2.85	2.74
	2,821.25	476.06	1,147.65	193.66	311.67	305.29

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	9.93	1.22	3.23	1.01	1.05	1.01
Combustion-Turbines	21.23	4.24	20.45	1.66	2.59	2.59
Combustion - HP & LP Flare	0.37	0.65	2.00	5.68	0.11	0.11
Supply Boat	19.05	1.00	4.17	2.04	1.70	1.63
Emergency Response	1.40	1.40	0.20	0.10	0.08	0.08
Survival Craft	0.01	0.52	1.22	0.00	0.14	0.14
Crew Boat	0.53	0.05	0.13	0.05	0.04	0.04
Pigging	–	0.00	–	–	–	–
Sumps/Tanks/Separators	–	2.03	–	–	–	–
Solvent Usage	–	3.14	–	–	–	–
Exempt Emissions	1.46	1.65	1.26	0.17	0.13	0.13
	53.97	15.89	32.64	10.71	5.84	5.73

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Combustion - Engines	40.70	4.26	13.13	3.56	4.28	4.13
Combustion-Turbines	78.68	11.67	50.72	4.99	5.27	5.27
Combustion - HP & LP Flare	1.47	2.60	7.98	22.71	0.43	0.43
Supply Boat	76.24	3.99	16.67	8.18	6.79	6.51
Emergency Response	5.61	0.17	0.78	0.41	0.33	0.32
Survival Craft	0.02	2.07	4.86	0.01	0.55	0.55
Crew Boat	1.44	0.16	0.39	0.16	0.13	0.12
Pigging	–	0.02	–	–	–	–
Sumps/Tanks/Separators	–	8.12	–	–	–	–
Solvent Usage	–	12.54	–	–	–	–
Exempt Emissions	5.78	6.57	5.07	0.66	0.52	0.50
	209.93	52.18	99.61	40.66	18.30	17.84

Table 5.4
Point Arguello Project Platform Hidalgo: Permit to Operate No. 9105
Exempt Emissions

C. PEAK QUARTERLY (tpq)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Helicopters	0.59	0.83	1.08	0.07	0.07	0.07
Surface Coating/Maintenance	--	0.76	--	--	--	--
	0.59	1.59	1.08	0.07	0.07	0.07

D. PEAK ANNUAL (tpy)

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Helicopters	2.33	3.29	4.32	0.26	0.27	0.26
Surface Coating/Maintenance	--	3.01	--	--	--	--
	2.33	6.30	4.32	0.26	0.27	0.26

5.6 *Hazardous Air Pollutants (HAPs)*

The following table summarizes the HAPs totals for this facility. Detail calculations for these HAPSs totals are maintained in the facility project file.

HAP	**Tpy**
Benzene	0.08
Toluene	0.10
Xylene	0.05
Formaldehyde	0.50
Acetaldehyde	0.07
PAH	0.01
Hexane	0.44
TOTAL	1.25

6.0 Air Quality Impact Analyses

6.1 Modeling

Air quality modeling was not required for the issuance of this OCS operating permit.

6.2 Increments

An increment analysis was not required for the issuance of this OCS operating permit.

6.3 Monitoring

Air quality monitoring was not required for the issuance of this OCS operating permit.

6.4 Health Risk Assessment

A Health Risk Assessment was not required for the issuance of this OCS operating permit.

7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

The Point Arguello Project Stationary Source is located in an ozone nonattainment area. Santa Barbara County is designated nonattainment for both the federal and state one-hour ambient air quality standards for ozone. In addition, the County is designated nonattainment with the state PM_{10} ambient air quality standard. Therefore, emissions from all emission units at the stationary source and its constituent facilities must be consistent with the provisions of the USEPA and State approved Clean Air Plans (CAP) and must not interfere with progress toward attainment of federal and state ambient air quality standards. Under APCD regulations, any modifications at Platform Hidalgo (or the Point Arguello Project Stationary Source) that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs/day must apply BACT (NAR). Additional increases may trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day.

7.2 *Clean Air Plan*

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.

7.3 *Offset Requirements*

Increases in county-wide emissions caused by a new project must be offset by commensurate reductions in emissions from another county source. 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 real, quantifiable, surplus, permanent, and enforceable. For permitted offset sources, a modification of existing permits is required to ensure that emission reductions will occur. For sources which are not owned or operated by the project applicant, a written agreement between the owner of the emission reduction source and the project applicant, with the APCD as third beneficiary, is required.

Chevron, the previous operator, entered into several agreements with the APCD identifying the sources of the emission reduction credits, the party providing the emission reduction credits (when not owned and operated by Chevron) and the specific reductions provided as offsets for the OCS platforms. A summary of these agreements and the offsets are provided in the *OCS Ozone Mitigation Agreement* (September, 1992).

The platform's emission totals (potential-to-emit) are detailed in the permits for each platform. 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 PTO 5704.

In addition, the permittee required SO_x offsets to comply with APCD Rule 359. These offsets were initially secured through the Marine Engine Repowering Program (MERC) which replaced engines on a number of boats with low-emission engines. The MERC emission reduction credits were subsequently replaced with credits generated by controlling emissions from three natural gas turbines on Platform Harvest. Project offsets are detailed in Table 7.3-1.

PXP also increased the permitted sulfur content of gas flared on the platform. This increase also was offset and the offsets are shown in Table 7.3-2.

7.4 *Emission Reduction Credits*

Platform Hidalgo generated 0.78 tons/year of ROC Emission Reduction Credits by implementing an enhanced Inspection & Maintenance Program on 725 gas valves and 1,450 associated connections. These ERCs are dedicated to offset the emissions from crude stabilization units installed on Platforms Harvest and Hermosa. The enhanced program consists of monthly rather than quarterly monitoring of the selected leak-paths. These ERCs are detailed in Table 7.4-1. The components in this program are listed in Attachment 10.4.

Table 7.3-1
PXP Platform Hidalgo - PTO 9105
Offset Requirements for Rule 359 Compliance

OXIDES OF SULFUR (SOx) [(a)]

Emissions Liability	TPY
Rule 359 Planned Flaring	3.50 SOx

Emission Reduction Sources	Emission Reductions tons/qtr	Distance Factor	Offset Credit tons/yr
ERC Certificate 0067[(b)]	0.044	1.0	0.044 SO_x
ERC Certificate 0137[(b)]	0.048	1.0	0.048 SO_x
ERC Certificate 1490[(c)]	3.408	1.0	3.408 SO_x
		Total	3.500

Provisions:

(a) Offsets for SO_x emissions are required for planned flaring pursuant to Rule 359 (§D.1.b)

(b) ERC Certificate 0067 contains 0.052 tpy SO_x ERCs. 0.008 tpy are provided to Platform Hermosa. The remainder (0.044) are have been assigned to Platform Hidalgo (PTO 9105-12). The full value of ERC Certificate 0137 is 0.051 tpy SO_x. 0.048 tpy has been assigned to Platform Hidalgo (PTO 9105-12), the remainder (0.003 tpy) is excess.

(c) The Harvest SCR ERC Project provides the remaining ERCs required for Platform Hidalgo (3.408tpy)

Table 7.3-2
Increase in Flare Gas Sulfur Content - Platform Hidalgo
Project Operation Emissions and Offsets

Sulfur Oxides (SOx)

NEI FROM PROJECT SUBJECT TO OFFSET PER RULE 359

Increase in Flare Gas Sulfur Content	TPQ	TPY
Planned Continuous	0.09	0.34
Planned Other	0.19	0.77
Total	0.28	1.12

EMISSION REDUCTION SOURCES

	Emission Reductions		Distance	Offset Credit	
	TPQ	TPY	Factor	TPQ	TPY
SOx Reductions From ERC Certificates 0033 & 0037	0.28	1.12	1.0	0.28	1.12
TOTAL	**0.28**	**1.12**		**0.28**	**1.12**

Notes:

a) ERCs per ERC Certificates 0033 & 0037; asssociated with the NEI in ATC/PTO 10260-01

b) Emission units: TPQ = tons per quarter; TPY = tons per year.

c) Determination of offset ratio ("distance factor"):
A distance factor is not used in calculating SOx offset Credits.

d) NEI subject to offset per Rule 359 reflects increase in
Planned Continuous sulfur content from 1.7 percent to 3.2 percent, and
Planned Other sulfur content from 1.7 percent to 2.07 percent.

\\sbcapcd.org\shares\Groups\ENGR\WP\PT70SRCE\PERMITS\O&G-PROD\Arguello - Harvest Hermosa Hidalgo\Platform Hidalgo\[Table 7.3-2 SOx Offset Table.xls]Table 10.1

Table 7.4-1
Platform Hidalgo
Permitted Gas-Side Fugitive ROC Emissions/Calculations

Column	A	B	C	D	E	F	G	H	I
Type	Component	Emission Factor	Uncont. THC	ROC/THC	Control		Controlled ROC Emissions		
	Leak Paths	lb THC/comp-lp day	lb/day	Ratio	Efficiency	lb/hr	lb/day	TPQ	TPY
Gas Service									
Valves/Connections	3738	0.2230	833.57	0.33	80%	2.29	55.02	2.51	10.04
Valves/Connections - unsafe	0	0.2230	0.00	0.33	0%	0.00	0.00	0.00	0.00
Valves: monthly	725	0.2230	161.68	0.33	84%	0.36	8.54	0.39	1.56
Valve Connections: monthly	1450	0.2230	323.35	0.33	82%	0.80	19.21	0.88	3.51
Valve Connections: unsafe	0	0.2230	0.00	0.33	0%	0.00	0.00	0.00	0.00
						3.45	82.76	3.78	15.10
Gas Totals	5,913		1,318.60						

lb/hr	lb/day	TPQ	TPY
3.45	82.76	3.78	15.10

Permitted Gas-Side Fugitive Emissions

Sample Calculations:

GAS
F = G/24
F = A*B*D*(1-E)
H = I/4
I = G*365/2000

lb/day	TPQ	TPY
59.05	2.69	10.78

ERCs Due to Enhanced I&M Program

Notes:
1) Baseline is from PTO 9105-06 (7/24/97). Gas controlled leak-paths = 9635 clp (valves/connections). Zero unsafe to monitor clps.
2) Gas service emission factors and ROC/THC ratio from APCD Policy and Procedure No. 6100-061-1996 Table 2, Offshore Platform.
3) Enhanced I&M program on specified valves and associated connections ("valve connections") provide ERCs that are registered pursuant to Rule 806.
4) The gas-side fugitive emissions listed in this table supercede the allowable gas-side fugitive emissions from PTO 9106-06.

\\sbcapcd.org\shares\Groups\ENGR\WP\PT70SRCE\PERMITS\O&G-PROD\Arguello - Harvest Hermosa Hidalgo\Platform Hidalgo\[Table 7.4-1 ROC ERCs.xls]Post ATC-PTO

8.0 Lead Agency Permit Consistency

A Final Development Plan for the Point Arguello Project (85-DP-32-CZ) was approved by the Santa Barbara County Board of Supervisors as lead agency in California. The approved Plan contains a number of provisions which relate to the air quality aspects of the project. These provisions are designated the "E" conditions. Of particular interest are conditions E-4 (requirements for ambient air quality monitoring stations to examine onshore project impacts) and conditions E-7 and E-9 (requirements that all NO_x and ROC emissions that contribute to ozone standard violations be completely mitigated). The project applicants and the County entered into a legally binding contract outlining the implementation of conditions E-4, E-7, and E-9. In 1992, E-4, E-7, E-9 contract was supplemented with an *OCS Ozone Mitigation Agreement* to clarify and augment requirements on ozone precursors.

The United States Department of Interior's Mineral Management Service approved the *Development and Production Plan* for Platform Hidalgo on January 15, 1985.

9.0 Permit Conditions

This section lists the applicable permit conditions for Platform Hidalgo. 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.

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 Platform Hidalgo. In the case of a discrepancy between the wording of a condition and the applicable APCD rule, the wording of the rule shall control.

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: PTO 9105*]

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: PTO 9105*]

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: PTO 9105*]

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 that follow the issuance of this PTO permit, including but not limited to permit condition implementation, implementation of Regulation XIII (*Part 70 Operating Permits*), 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: PTO 9105, APCD 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: PTO 9105*]

A.6 **Compliance:** Nothing contained within this permit shall be construed to allow the violation of any local, State or Federal rule, regulation, ambient air quality standard or air quality increment. [*Re: PTO 9105*]

A.7 **Consistency with Analysis:** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the APCD's project file) and the APCD's analyses under which this permit is issued as documented in the permit analyses prepared for and issued with this permit. [*Re: PTO 9105*]

A.8 **Consistency with State and Local Permits:** Nothing in this permit shall relax any air pollution control requirement imposed on the Point Arguello Project by:

(a) The County of Santa Barbara in the *Chevron/Point Arguello Project Final Development Plan No. 85-DP-32-CZ* and any subsequent modifications (including the September 1992 *Ozone Mitigation Agreement for the Point ArguelloProject*, the amended September 1992 *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*, and all subsequent amendments or revisions.

(b) The Santa Barbara County Air Pollution Control APCD in Authority to Construct 5704, Permit to Operate 5704, and any subsequent modifications to either permit; and

(c) The California Coastal Commission in the consistency determination for the Project with the California Coastal Act. [*Re: PTO 9105*]

A.9 **Compliance with Department of Interior Permits:** PXP shall comply with all air quality control requirements imposed by the Department of the Interior in the *Development and Production Plan* for Platform Hidalgo on January 15, 1985 and any subsequent modifications. Such requirements shall be enforceable by the APCD. [*Re: PTO 9105*]

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 re-issuance, 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 Rules 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 2-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 Plans:**

(a) The Compliance Plans for the stationary source, submitted by the permittee on application Forms 1302-I (1 & 2) and 1302-J (1 & 2), are a part of this permit.

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

(c) 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 s 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-days after the date of occurrence. The report shall clearly document 1) the probable cause and extent of the deviation, 2) equipment involved, 3) the quantity of excess pollutant emissions, if any, and 4) actions taken to correct the deviation. The requirements of this condition shall not apply to deviations reported to 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, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations 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 August 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, 1302.D.3, 1303.2.c*]

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)*]

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, then it will be reissued with the expiration date applicable to the re-opened permit. [*Re: 40 CFR 70.7(f), 40 CFR 70.6(a)*]

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. These rules apply to the equipment and operations at Platform Hidalgo as they currently exist. Compliance with these requirements is discussed in Section 3.4.2. In the case of a discrepancy between the wording of a condition and the applicable APCD rule, the wording of the rule shall control.

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

Offshore Flaring: For planned flaring (other than purge and pilot and planned continuous as per Table 5.1-1 of this permit), a visible emissions inspection for a one-minute period shall be performed once per quarter during a planned flaring event. If visible emissions are detected during the quarterly inspection, then a USEPA Method 9 visible emission evaluation (VEE) shall immediately be performed for a six-minute period or the duration of the flaring event, 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.

Failure to perform a required Method 9 inspection will not constitute a violation if the attempted VEE can not be performed in accordance with procedures of Section 2 of Method

9 due to existing ambient conditions at the platform during the inspection and PXP fully documents the conditions that preclude the performance of the VEE.

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.

Offshore Platform Cranes: During biennial source testing of each crane, PXP shall perform a visible emissions inspection on the crane for a one-minute period. If visible emissions are detected during any inspection, then a USEPA Method 9 visible emission evaluation (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.

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 **PM Concentration - South Zone (Rule 305):** PXP shall not discharge into the atmosphere, from any source, particulate matter in excess of the concentrations listed in Table 305(a) of Rule 305. [*Re: APCD Rule 305*]

B.4 **Specific Contaminants (Rule 309):** PXP shall not discharge into the atmosphere from any single source sulfur compounds, carbon monoxide and combustion contaminants in excess of the applicable standards listed in Sections A, E and G of Rule 309. [*Re: APCD Rule 309*]

B.5 **Sulfur Content of Fuels (Rule 311):** PXP shall not burn fuels with a sulfur content in excess of 0.0015% (by weight) for liquid fuels and 239 ppm_{vd} or 15 gr/100 scf (calculated as H_2S) for gaseous fuel. Compliance with this condition shall be based on daily measurements of the fuel gas using (Draeger tubes, ASTM, or other APCD-approved) methods and diesel fuel billing records or other data showing the certified sulfur content for each shipment. [*Re: APCD Rule 311*]

B.6 **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's compliance with Condition C.8 (*Solvent Usage*) of this permit. [*Re: APCD Rule 317*]

B.7 **Vacuum Producing Devices or Systems - Southern Zone (Rule 318):** PXP shall not discharge into the atmosphere more than 3 pounds of organic materials in any one hour from any vacuum producing devices or systems, including hot wells and accumulators, unless said discharge has been reduced by at least 90-percent. [*Re: APCD Rule 318*]

B.8 **Solvent Cleaning Operations (Rule 321):** PXP shall comply with the requirements listed in Sections D, G, I, P and Q of Rule 321. Compliance with this condition shall be based on PXP's compliance with Condition C.8 (*Solvent Usage*) of this permit as well as APCD inspections. [*Re: APCD Rule 321*]

B.9 **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's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 322*]

B.10 **Architectural Coatings (Rule 323):** PXP shall comply shall comply with the coating ROC content and handling standards listed in Rule 323.D as well as the Administrative requirements listed in Rule 323.F. Compliance with this condition shall be based on PXP's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 323*]

B.11 **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's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 324*]

B.12 **Adhesives and Sealants (Rule 353):** The permittee shall not use adhesives, adhesive bonding primers, adhesive primers, sealants, sealant primers, or any other primers, unless the permittee complies with the following:

(a) Such materials used are purchased or supplied by the manufacturer or suppliers in containers of 16 fluid ounces or less; or alternately

(b) When the permittee uses such materials from containers larger than 16 fluid ounces and the materials are not exempt by Rule 353, Section B.1, the total reactive organic compound emissions from the use of such material shall not exceed 200 pounds per year unless the substances used and the operational methods comply with Sections D, E, F, G, and H of Rule 353. Compliance shall be demonstrated by recordkeeping in accordance with Section B.2 and/or Section O of Rule 353. *[Re: APCD Rule 353]*

B.13 **Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers (Rule 360):** This rule applies to water heaters, boilers, steam generators and process heaters with rated heat input capacities greater than or equal to 0.75 MMbtu/hr up to, and including, 2.0 MMbtu/hr. There are no units at this facility subject to this rule. [*Re: APCD Rule 360*]

B.14 **Oil and Natural Gas Production MACT:** As discussed in section 3.2.5 above, this facility is exempt from this MACT, however PXP is required, and shall, maintain records in accordance with 40 CFR 63.10(b)(3). *[Ref: 40 CFR 63, Subpart HH]*

9.C Requirements and Equipment Specific Conditions

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

C.1 **Internal Combustion Engines**: The following equipment are included in this emissions unit category:

EQ Device No.	Name
005058	West Pedestal Crane (475 bhp)
005059	East Pedestal Crane (475 bhp)
005432	Turbine Starter Engine 6-91 (225 bhp)
005433	Turbine Starter Engine 6-92 (225 bhp)
005434	Turbine Starter Engine 6-93 (225 bhp)
005435	Turbine Starter Engine 6-94 (225 bhp)

(a) Emission Limits: Mass emissions from the east and west pedestal crane engines and the turbine starter engines listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition, the following specific emission limits apply:

(i) *Pedestal Crane Engines*: Controlled emissions of NO_x from each diesel fired crane engine shall not exceed either 8.4 g/bhp-hr or 797 ppmvd at 15-percent oxygen or 2,400 ppmv at 3-percent oxygen. Compliance shall be based on quarterly inspections and biennial source testing. More frequent testing may be required, as determined by the APCD, if quarterly portable NO_x analyzer results show potential exceedances of the standard.

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

(i) *Turbine Starter Engines:* Each diesel-fired turbine starter IC engine shall be operated for no more than 60-minutes per day, 200 hours per calendar quarter and 200 hours per calendar year each.

(ii) *Emission Controls*: PXP shall implement the requirements of APCD Rule 333. NO_x emissions from the cranes shall be reduced by using turbocharged engines with injection timing retarded by 4 degrees the cranes and shall be equipped with a separate intercooling circuit.

(iii) *Liquid Fuel Sulfur Limit*: Diesel fuel used by all IC engines shall have a sulfur content no greater than 0. 0.0015 weight percent as determined by APCD-approved ASTM methods.

(iv) *Fuel Use Limits*: PXP shall comply with the following fuel limits:

- The west pedestal crane engine shall not use more than: 569 gallons per day; 18,851 gallons per quarter; 79,406 gallons per year of diesel fuel.

- The east pedestal crane engine shall not use more than: 569 gallons per day; 18,851 gallons per quarter; 79,406 gallons per year of diesel fuel.

(v) *Engine Identification and Maintenance*: Each IC engine shall be identified with a permanently-affixed plate, tag or marking, referencing either: (i) the IC engine's make, model, serial number, rated BHP and corresponding RPM; or (ii) the operator's unique tag number. The tag shall be made accessible and legible to facilitate APCD inspection of the IC engine.

(c) Monitoring: The following source testing and periodic monitoring conditions apply to the pedestal crane, turbine starter, emergency generator and the emergency fire water pump engines:

(i) *Hour Meters*: PXP shall operate and properly maintain a dedicated, non-resettable elapsed-time meter on each turbine starter engine.,

(ii) *Fuel Meters*: The amount of fuel combusted in each engine shall be measured using permanently installed APCD-approved in-line fuel meters dedicated to each engine. As an alternative to in-line fuel meters, PXP may report individual engine hours of operation utilizing a APCD-approved elapsed time meter [6]. A monthly log shall be maintained that records the fuel usage (or hours of operation) of each engine.

(iii) *Inspection and Maintenance Plan (I&M Plan)*: PXP shall implement quarterly inspections on the each engine according to the APCD-approved *Engine Inspection and Maintenance Plan* consistent with the requirements of Rule 333. This Plan, and any subsequent APCD-approved revisions, is incorporated by reference as an enforceable part of this permit.

(iv) *Source Testing*: For each pedestal crane engine, PXP shall perform source testing of air emissions and process parameters consistent with the requirement of the *Source Testing* permit condition below and in accordance with the requirements of Rule 333.

(v) *Fuel Data*: PXP shall maintain documentation of the sulfur content (as determined by APCD-approved ASTM methods) of each diesel fuel shipment as certified in the fuel suppliers billing vouchers.

d) Recordkeeping: PXP shall keep the required logs, as applicable to this permit, which demonstrate compliance with emission limits, operation limits and monitoring

[6] The hours of operation, along with the engine horsepower rating and BSFC data as listed in Table 5.1-1 of this permit, a fuel correction factor of 1.06, and a high heating value of 138,200 Btu/gal is used to determine the number of gallons of fuel consumed per time period.

requirements above. All logs shall be available to the APCD upon request. Written information (logs) shall include:

(i) Daily, quarterly and annual fuel usage in units of gallons for the pedestal crane engines.

(ii) The hours of operation for each turbine starter engine. The log shall detail the number of operating hours on each day the engine is operated and the total monthly and cumulative annual hours.

(iii) The sulfur content (as determined by APCD-approved ASTM methods) of each fuel shipment as certified in the fuel suppliers billing vouchers. On an annual basis, the higher heating value of the diesel fuel (Btu/gal) shall be recorded. The billing vouchers shall be attached to the log.

(iv) IC engine operations logs, including quarterly inspection results, consistent with the requirements of Rule 333.

(v) If an operator's tag number is used in lieu of an IC engine identification plate, documentation which references the operator's unique IC engine ID number to a list containing the make, model, serial number, rated maximum BHP and the corresponding RPM.

(e) Reporting: On a semi-annual basis, a report detailing the previous six month's activities shall be provided to the APCD. The report must list all data required by the *Compliance Verification Reports* condition of this permit. (*Re: APCD Rules 202, 311, 333 and 1303, PTO 9105, ATC/PTO 11082, 40 CFR 70.6*)

C.2 **Turbines:** The following equipment are included in this emissions unit category:

EQ Device No.	Name
005040	Turbine G-91 (2,800 kw)
005041	Turbine G-92 (2,800 kw)
005042	Turbine G-93 (2,800 kw)
005043	Turbine G-94 (3,100 kw)

(a) Emission Limits: Except during start-up, shutdown, periods when maintenance on turbine monitoring equipment is occurring, and G-94 transient load situations as prescribed below, mass emissions from the turbines listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition, the following specific emission limits apply:

(i) *Turbines G-91, G-92 and G-93*: Each turbine shall be operated such that the emissions of NO_x, ROC and CO do not exceed the emission factor algorithms listed below. Compliance shall be based on the source testing requirements as listed in Table 4.1.

For NO_x emission calculations:

$$ER_{fuel\ gas} = 1.0 + 0.02935 \text{ x } kW^{0.668}$$

$$ER_{diesel} = 2.5 + 0.000801 \text{ x } kW^{1.085}$$

For ROC emission calculations[7]:

$$ER_{fuel\ gas} = 0.5675 \text{ x } kW^{0.03}$$

Uncontrolled:

$$ER_{diesel} = 2.22 + (.00016 \text{ x } kW)$$

Controlled:

$$ER_{diesel} = 2.84 - (0.00058 \text{ x } kW)$$

For CO emission calculations:

$$ER_{fuel\ gas} = (0.0014 \text{ X } kW) + 0.6242$$

$$ER_{diesel} = 1.2475 \text{ x } e^{(0.0007 \text{ x } kW)}$$

Where:

ER = emission rate (lbs/hour)
kW = kilowatts

(ii) *Turbine G-94*: NO_x emissions from SoLoNOx Turbine Generator G-94 shall not exceed 25 ppm_v (dry at 15% excess oxygen, measured at ISO conditions) when operated at loads greater than 50% of maximum rated capacity (1,550 Kilowatts) while operated on platform produced natural gas. *[Re: PTO 9105-06]*

(iii) NO_x concentrations from the G-91, G-92 and G-93 turbines shall not exceed 150 ppmvd (as NO_2) at 15 percent O_2.

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

(i) *Turbine G-91*: Turbine generator G-91 shall operate no more than 550 hours per calendar year. Upon written approval by the APCD, PXP may operate turbine G-91 up to an additional 50 hours per year to conduct source tests on the turbine. *[Re: PTO 9105-06]*

(ii) *Turbine G-94*: Turbine generator G-94 shall not use diesel fuel. *[Re: PTO 9105-06]*

[7] Uncontrolled emissions are at operations less than 650 kW. Water injection starts for control purposes at 650 kW and the equation for controlled emissions is utilized.

(iii) *Turbine G-94 Transient Loads*: PXP shall limit all transient load situations for $SoLoNO_x$ Turbine G-94 in order to minimize runtime in the turbine's uncontrolled range (less than 40% load or 1,200 KW). Operational transient load swings (not including turbine start-up and shutdown) shall be limited to a maximum of one (1) hour per event and a maximum cumulative total of ten (10) hours per calendar quarter for Turbine G-94. To ensure compliance with this condition, PXP shall implement a Standard Operating Procedure (SOP) developed specifically for Turbine G-94. The SOP shall specify, among other things, how platform operators will handle transient load situations, and when and how to perform starts and stops on the turbine, to minimize runtime below 40% operating load. *[Re: PTO 9105-06]*

(iv) *Fuel Use Limits*: PXP shall comply with the following fuel limits:

- *Turbine G-91* shall not use more than: 7,515 gallons per day; 187,875 gallons per quarter; 187,875 gallons per year of diesel fuel.

- *Turbine G-91* shall not use more than: 937,241 standard cubic feet per day; 21.478 million standard cubic feet per quarter; 21.478 million standard cubic feet per year of fuel gas.

- *Turbines G-92 and G-93* shall each not use more than: 7,515 gallons per day; 274,001 gallons per quarter; 548,001 gallons per year of diesel fuel.

- *Turbines G-92 and G-93* shall each not use more than: 937,241 standard cubic feet per day; 85.523 million standard cubic feet per quarter; 342.093 million standard cubic feet per year of fuel gas.

- *Turbine G-94* shall not use diesel fuel.

- *Turbine G-94* shall not use more than: 1,022,715 standard cubic feet per day; 93.323 million standard cubic feet per quarter; 373.291 million standard cubic feet per year of fuel gas.

(v) *Fuel Gas Sulfur Limit:* The sulfur content of fuel gas combusted as turbine generator gas shall not exceed 50 ppm_v total sulfur calculated as hydrogen sulfide (at standard conditions). The ppm_v limit for the turbine fuel gas shall be based on a 15-minute average. Compliance shall be based on in-line continuous monitoring using an APCD-approved hydrogen sulfide analyzer. This analyzer shall be operated consistent with the requirements of the APCD's CEM Protocol document (dated October 22, 1992 and subsequent updates), where applicable. PXP shall implement the monitoring, calibration, recordkeeping and reporting procedures contained in the approved *Fuel Gas Reporting Plan.* PXP shall operate the amine based fuel gas sweetening system at all times when combusting fuel gas in the turbines and as purge/pilot fuel.

(vi) *Fuel Sulfur Content Excursions*: For specific events as defined below, the sulfur content of the gaseous fuel burned in the turbines may be excluded from the 50 ppm_v 15-minute average calculation defined above. However, at no time shall the fuel sulfur content exceed 15 grains per 100 cubic feet (239 ppm_v). The specific events not subject to the 50 ppm_v sulfur limit are:

- Turbine start-up on gaseous fuel after running on diesel fuel.
- Turbine start-up on gaseous fuel after having been shutdown.

Each event shall be limited to no more than one (1) hour in duration. The total number of events shall be limited to six (6) per calendar quarter and twelve (12) per calendar year.

PXP shall record the date, time and duration of each event in a log, along with the peak sulfur content during the excursion. A copy of this log shall be included in the platform's quarterly report.

(vii) *ADGS System*: PXP shall comply with the requirements of the *Turbine Automated Data Gathering System Assurance Plan.*

(vi) *Emission Reduction Efficiency*:

(1) *Turbines G-91, G-92 and G-93:* At full safe load for either fuel gas or diesel use modes, NO_x emissions shall be controlled to a rate which is 30-percent or less of the uncontrolled emission levels at full safe load.

(vii) *Water Injection Criteria*:

(1) *Turbines G-91, G-92 and G-93*: The project will use water injection in the turbines when the operating load is 650 kilowatts or greater.

(2) *Turbine G-94*: None

(viii) *Water Injection Ratios*:

(1) *Turbines G-91, G-92 and G-93*: PXP shall maintain a minimum water to fuel (W/F) ratio (weight basis) controller set point of 0.80 when operating turbines with either fuel gas or diesel at loads greater than or equal to those specified in item (vii) above. PXP shall maintain water injection ratios a minimum of 96-percent of the time (on an annual basis, based on the average time of operation with and without water injection for combined diesel and fuel gas use) when operating at loads or fuel use greater than or equal to those specified in item (vii) above.

(2) *Turbine G-94*: None

(ix) *Diesel Use*:

(1) *Turbines G-91, G-92 and G-93*: Diesel fuel use in turbines shall be limited to cases of emergency or when otherwise required for safety reasons, or when fuel gas is unavailable at volumes required to operate the turbine. Diesel fuel used by

these turbines shall have a sulfur content no greater than 0.0015 percent by weight.

(2) *Turbine G-94*: Diesel shall not be used in the SoLoNOx turbine.

(x) *Meters*: All OCS turbine generators and compressors shall be equipped with elapsed time meters and fuel meters.

(xi) *Quality Assurance*: PXP shall implement the APCD-approved *Process Monitor and Calibration and Maintenance Plan* on water and fuel meters, and injection controllers, to ensure maintenance of proper water injection ratios.

The Automatic Data Gathering System (ADGS) system may be audited independently by the APCD, or APCD-approved representatives, once per year in order to ensure compliance with proper quality control procedures to verify the accuracy of the recording devices.

(c) Monitoring: The following source testing and periodic monitoring conditions apply to the turbines:

(i) *Process Stream Sampling and Analysis*: PXP shall sample and analyze the process streams listed in Section 4.12 of this permit consistent with the requirements of that section. All process stream samples shall be taken according to APCD-approved ASTM methods and must be follow traceable chain of custody procedures.

(ii) *Water Injection*. PXP shall measure the water injection and fuel use rates for the purpose of establishing the average hourly water injection ratio. The procedures and equipment necessary to monitor and report this ratio are fully described in the Turbine ADGS Quality Assurance Plan.

(iii) *Source Testing*: PXP shall source test turbines G-91, G-92 and G-93 on Platform Hidalgo at least once per calendar year, (except as noted below), with water injection at the injection ratio specified above. The NO_x water injection ratio shall be determined from current fuel gas densities, as determined from fuel gas samples taken within 14-days immediately prior to testing. If the NO_x water controllers are not updated with the new fuel gas densities, the W/F setpoint shall be set such that the actual W/F ratio is as specified above. Turbines may be tested at as-found loads, unless otherwise requested by the APCD. Any turbine operated on fuel gas less than 877 hours in the previous calendar year, or as otherwise approved by the APCD, may be exempted from source testing requirements. The minimum time period between annual tests shall be 3-months.

Turbine G-94 shall be tested at least once per calendar year. Testing shall be performed at the typical operating load over the previous 12-month period unless otherwise specified by the APCD, to demonstrate both the relative accuracy of the Predictive Emissions Monitoring System (PEMS) to within 15-percent. as well as compliance with the emissions concentration and mass limits.

If required by the APCD, uncontrolled emission factors may be confirmed during annual source testing as well.

If at the time of source testing, a turbine is inoperable due to reasons beyond the reasonable control of the platform operator, that turbine shall be exempted from testing for that calendar year. However, only one turbine generator per platform per calendar year may be exempted from testing, and no turbine may be exempted from testing for two consecutive calendar years. To qualify for this exemption, prior to source testing the PXP must provide the APCD with:

1) Turbine number, the date of breakdown, the nature and probable cause of the problem, the anticipated date of repair; and
2) Other information sufficient for the platform operator to demonstrate that the turbine is inoperable.

If diesel use on Platform Hidalgo exceeds 10-percent of the total turbine generator operating time for the previous calendar year for the platform, the permittee shall also test each turbine generator on the platform with diesel fuel in the controlled mode with water injection at the injection ratio specified above.

(iv) *Access to Source Tests*: Upon request, the permittee shall allow APCD personnel, or its designated agent to be present during source testing of the turbines. The permittee shall provide access and transportation to the APCD personnel or its designated agent for the purposes of observing the source tests.

(v) *Turbine G-94 Predictive Emissions Monitoring System (PEMS) Accuracy Testing Correction:* During the annual testing of the turbines, the relative accuracy of the PEMS shall be verified. If the relative accuracy of the PEMS (based upon the NO_x concentration and mass rate (ppmv and lbs/hour) is greater than +/- 15% applicable limit at any source test load, the PEMS model shall be recalibrated by the manufacturer's representative during the on-site testing. Alternatively, if the manufacturer's representative is not available or recalibration is otherwise not possible, a correction factor may be applied to a load range (e.g. 50-75%, 75-100%, or other specified range) in which the PEMS accuracy is greater than +/- 15%. The correction factor will be an upward or downward adjustment to the PEMS value by the percent relative error calculated per the Relative Accuracy Audit equation in 40 CFR 60, Appendix F. A post-validation test shall be performed to confirm the accuracy of the "corrected" PEMS value.

No calibration or correction need be applied if the PEMS accuracy is within +/- 15% applicable limit at each load.

(d) Recordkeeping: The Automatic Data Gathering System (ADGS) shall collect and record instantaneous readings of the following parameters for each turbine every three minutes. This data shall be maintained for a period of one year.

(i) Date and time of reading.

(ii) Kilowatts (generators only).

(iii) Fuel rate, including diesel (generators only) and the fuel gas.

(iv) Water rate.

(v) For the G-91, G-92 and G-93 turbines, the average hourly water/fuel (W/F) ratio (mass basis). Approximate densities of the fuel and water shall be as follows: diesel, 7.30 lb/gallon; fuel gas, no less than current tested density; water, 8.34 lb/gallon.

(vi) For each turbine, requiring water injection the total cumulative time for each quarter that the water to fuel ratio fell below 0.80, the total cumulative time water was required to be injected and the annual (calendar) percentage of time that water was injected while the turbines operated above 650 kw.

(vii) Mass emissions for each turbine.

(viii) Daily summaries containing hourly averages or totals of the above process parameters and hourly totals of emissions.

Upon request by the APCD, the Project shall provide logs of chronological three-minute data of the above parameters at operating loads below 1200 M, including "run status," i.e., starting, stopping, or "running" (load transients).

The permittee shall make the best efforts to achieve a minimum data retrieval rate of 95-percent for each measurement, determined on a quarterly basis.

(e) Reporting:

(i) *Turbines G-91, G-92 and G-93*: Emissions reported shall be based on the following equations:

For NO_x emission calculations:

$$ER_{fuel\ gas} = 1.0 + 0.02935(kW)^{0.668}$$

$$ER_{diesel} = 2.5 + 0.000801(kW)^{1.085}$$

For ROC emission calculations[8]:

$$ER_{fuel\ gas} = [0.5675(kW)^{0.03]}$$

Uncontrolled:

$$ER_{diesel} = 2.22 - + (0.00016 X kW)$$

[8] Uncontrolled emissions are at operations less than 650 kW. Water injection starts for control purposes at 650 kW and the equation for controlled emissions is utilized.

Controlled:

$ER_{diesel} = 2.84 - (0.00058 \text{ X kW})$

For CO emission calculations:

$ER_{fuel\ gas} = (0.0014 \text{ x Kw}) + 0.6242$

$ER_{diesel} = 1.2475 * e^{(0.0007 * kW)}$

Where:

ER = emission rate (lbs/hour)
kW = kilowatts
Uncontrolled emissions occur when no water injection is used.
Controlled emissions occur when water injection is used.

(ii) *Turbine G-94*: NO_x, ROC and CO emissions shall be computed from the ADGS data using the emission factors specified below. Controlled emissions may be calculated when the operating load is equal to or greater than 1,200 kW Uncontrolled (i.e., transient loads) emission factors must be used to calculate emissions at all times when the operating load falls below 1,200 kW.

FUEL GAS

NO_x Emissions

Uncontrolled (lbs/hour) = 3.46

Controlled (lbs/hour) = PEMS*

ROC Emissions

Uncontrolled (lbs/hour) = 195.02 – 0.12 (kW)

Controlled (lbs/hour) = 0.36

CO Emissions

Uncontrolled (lbs/hour) = 205.00

Controlled (lbs/hour) = 0.000306 (kW) + 2.77

* The Predictive Emissions Monitoring System uses the following measured ambient conditions and turbine control parameters in a mathematical model (proprietary to Solar Turbines Inc.) to calculate emission concentrations and mass flows:

- Turbine inlet temperature
- Ambient temperature
- Ambient absolute temperature
- Relative humidity

(iii) *Manual Calculations*: The average hourly emission rate (determined by dividing the total emissions by the actual operating time during which the ADGS was operational for that calendar quarter), time the number of hours of ADGS downtime, shall be used to estimate emissions occurring during ADGS downtimes.

(iv) 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 the *Compliance Verification Reports* condition of this permit. (*Re: APCD Rules 202, 311, 333 and 1303, PTO 9105, ATC/PTO 9947 ATC/PTO 10851, 40 CFR 70.6*)

C.3 **Combustion Equipment – Flare:** The following equipment are included in this emissions unit category:

EQ Device No.	Name
05423	High Pressure and Low Pressure Flare

(a) Emission Limits: Flaring emissions from the purge and pilot, planned continuous, planned intermittent (other) and unplanned events shall not exceed the volumes in Table 5.1-1 and the emission limits in Tables 5.1-3 and 5.1-4.

(b) Operational Limits:

(i) *Flaring Volumes*: Flaring volumes from the purge and pilot, planned continuous, planned (other) and unplanned events shall not exceed the volumes in Table 5.1-1.

(ii) *Planned Flaring Operational Limits*: The permittee shall not combust in the flare, any combination of planned flaring events (as defined by Rule 359), any more than:

(1) 100,000 standard cubic feet in any one-hour period (60-minute sliding scale)

(2) 300,000 standard cubic feet in any three-hour period (180-minute sliding scale)

(3) 500,000 standard cubic feet in any 24-hour period (24-hour sliding scale)

The above limits do not apply to flare purge and pilot gas volumes. *[ATC/PTO 9905, PTO 9105-02]*

(iii) *Flare Purge/Pilot Fuel Gas Sulfur Limits:* The sulfur content of fuel gas combusted as purge and pilot gas shall not exceed 165 ppm_v total sulfur calculated as hydrogen sulfide (at standard conditions). The ppm_v limit for the purge/pilot gas shall be based on a 15-minute average. Compliance shall be based on in-line continuous monitoring using a hydrogen sulfide analyzer. The permittee shall obtain APCD-approval on the analyzer design specifications prior to any modification. This analyzer shall be operated consistent with the requirements of the APCD's CEM Protocol document (dated October 22, 1992 and subsequent updates), where applicable. The permittee shall implement the monitoring, calibration, recordkeeping and reporting procedures contained in the approved Fuel Gas Reporting Plan. The permittee shall operate the amine based fuel gas sweetening system at all times when combusting fuel gas as purge/pilot fuel.

(iv) *Fuel Sulfur Content Excursions*: For specific events as defined below, the sulfur content of the flare purge/pilot gaseous fuel may be excluded from the 165 ppm_v 15-minute average calculation defined above. However, at no time shall the fuel sulfur content exceed 15 grains per 100 cubic feet (239 ppm_v). The specific events not subject to the 165 ppm_v sulfur limit are:

- Platform start-up on gaseous fuel after running on propane.
- Platform start-up on gaseous fuel after having been shutdown.

Each event shall be limited to no more than one (1) hour in duration. The total number of events shall be limited to six (6) per calendar quarter and twelve (12) per calendar year.

PXP shall record the date, time and duration of each event in a log, along with the peak sulfur content during the excursion. A copy of this log shall be included in the platform's semi-annual report.

(v) *Flare Planned Continuous Flaring Sulfur Limits:* The sulfur content of all gas burned as planned continuous flaring in the flare header shall at no time exceed 32,000 ppmv total sulfur. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(vi) *Flare Planned (other) Sulfur Limits:* The sulfur content of all gas burned as planned (other) in the flare header shall not exceed 20,700 ppmv total sulfur. This limit shall be enforced on an average quarterly basis (i.e., the average of all sulfur content measurements during the quarter). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(vii) *Use of Propane as Fuel Gas:* Propane may be used as an auxiliary fuel to the flare purge and pilot fuel gas. 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).

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

(c) Monitoring: The equipment in this section is subject to all the monitoring requirements listed in APCD Rule 359.G. The test methods In Rule 359.E. shall be used. In addition, PXP shall:

(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 PXP's *Process Monitor Calibration and Maintenance Plan.*

(ii) *Pilot Flame Detection*: PXP shall continuously monitor each pilot to ensure that a flame is present at each pilot at all times.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirement listed in Rule 359.H. In addition, PXP shall:

(i) *Flare Event Logs:* All flaring events shall be recorded in a 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); and, a qualitative description of the gas flared including estimates of the sulfur content from the most recent measurements.

(ii) *Sulfur Content*: A log of the total sulfur content of produced gas combusted during flaring events shall be maintained.

(iii) *Propane as Flare Fuel Gas*: 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.

(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 the *Compliance Verification Reports* condition of this permit. (*Re: APCD Rules 359 and 1303, PTO 9105, ATC/PTO 10331, 40 CFR 70.6*)

C.4 **Fugitive Hydrocarbon Emissions Components:** The following equipment are included in this emissions unit category:

EQ Device No.	Name
103244	*Oil Service Components*
--	Oil – Controlled
--	Oil – Unsafe
103244	*Gas/Light Liquid Service Components*
--	Gas – Valves/Connections
--	Gas – Valves/Connections Unsafe
--	Gas – Valves Monitored Monthly
--	Gas – Connections Monitored Monthly

(a) Emission Limits: Mass emissions from the gas/light liquid service and oil service components listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4.

(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 with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition PXP shall meet the following requirements:

(i) *VRS Use:* The vapor recovery/gas collection (VRGC) system shall be in operation when the equipment connected to the VRGC system at the facility is in use. The VRGC system includes piping, valves, and flanges associated with the VRGC system. The VRGC system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(ii) *I&M Program*: The APCD-approved *Rule 331 Inspection and Maintenance Plan* for Platform Hidalgo shall be implemented for the life of the project. The Plan, and any subsequent APCD approved revisions, is incorporated by reference as an enforceable part of this permit.

(iii) *Leak-Path Count:* The total leak-path component count listed in PXP's most recent I&M component leak-path inventory shall not exceed the total leak-path component count listed in Table 5.1-1 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) *Venting*: All routine venting of hydrocarbons shall be routed to either the sales compressor, flare header, injection well or other APCD-approved control device.

(v) *Rule 331 BACT:* There are no components subject to BACT on Platform Hidalgo.

(vi) *Fugitive Emission Decrease Calculation Re-Opener*: The value of the emission reduction credits due to the implementation of the Enhanced I&M Program may be recalculated if the protocol for determining fugitive emissions at Platform Hidalgo changes.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements listed in APCD Rule 331.F. The test methods in Rule 331.H shall be used, when applicable. In addition the permittee shall meet the following requirements:

(i) *Monthly Monitoring*: PXP shall perform monthly monitoring on 725 standard (i.e., non-bellows seal and non-low emissions) valves and an associated 1,450 connections in order to generate the ERCs for ERC Certificate No. 0005. PXP shall replace any valve/connection on the list with a replacement if the valve/connection is no longer in hydrocarbon service unless the component has been permanently removed from service. The APCD shall be notified, in writing, of all such replacements within 90-days after the replacement. The notification shall include a complete equipment description information and the reason for the replacement. Subsequent I&M records and reports shall include the replacement valve(s). *[ATC/PTO 9883]*

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

(i) *I&M Log:* PXP shall 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.

- In accordance with condition (c)(i) above, for the valves/connections monitored monthly as part of the Enhanced I&M Program, maintain on a monthly basis a record that all the valves/connections were monitored in accordance with c(i) above.

- For the valves/connections monitored monthly as part of the Enhanced I&M Program, maintain a record of information concerning leaks and repairs similar to that contained in PXP's "Leak Summary" table submitted with the Semi-Annual Compliance Verification Reports, to include location, P&ID number, tag number, component, leak rates (ppm and drop-per-minute), date inspected, date of repair, days to repair, and re-inspection data and results.

For the purpose of the above paragraph, a leaking component is any component which exceeds the applicable limit (e.g., greater than 1,000 ppmv for minor leaks under Rule 331).

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 331.G. 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 the *Compliance Verification Reports* (CVR) condition of PTO 9105. As a separate and identifiable part of the Leak Summary table of each CVR, provide a copy of the Recordkeeping requirements listed above for the Enhanced I&M Program. [*Re: APCD Rules 331 and 1303, ATC 10775,* ATC/PTO 9883, *40 CFR 70.6*]

C.5 **Crew and Supply Boats**: The following equipment are included in this emissions category:

EQ Device No.	Name
Supply Boat	
005426	Supply Boat Main Engines – Controlled (5,000 bhp total)
005426	Supply Boat Main Engines – Uncontrolled (5,000 bhp total)
103117	Supply Boat Auxiliary Engines (600 bhp total)
105053	Supply Bow Thruster (515 bhp total)
Crew Boat	
103109	Crew Boat Main Engines – Controlled (1,530 bhp total)
103109	Crew Boat Main Engines – Uncontrolled (1,530 bhp total)
103117	Crew Boat – Generator (218 bhp total)
Emergency Response Boat	
105094	Emergency Response Main/Aux Engines (4,400 bhp total)
103121	Marine Survival Craft (62 Bhp)
103122	Marine Survival Craft (62 Bhp)
103123	Marine Survival Craft (36 Bhp)

(a) Emission Limits: Mass emissions from the crew, supply and emergency response boats listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit. In addition:

(i) With the exception of the Santa Cruz, controlled emissions of NO_x from each diesel fired main engine in each controlled crew boat and controlled supply boat shall not exceed 337 lb/1000 gallons (8.4 g/bhp-hr). Controlled emissions of NO_x from each diesel fired main engine of the Santa Cruz shall not exceed 270 lb/gal (5.99 g/bhp-hr). Spot charter supply boats and emergency response (e.g., *Clean Seas*) boats shall not be required to comply with this controlled NO_x emission rate. Compliance shall be based on annual source testing consistent with the requirements listed in Table 4.1 and permit Condition 9.C.18.

(ii) The combined emissions from all supply boats serving the OCS platforms in the Point Arguello Project (Platforms Harvest, Hermosa and Hidalgo) shall not exceed the emission limits listed in Table 9.1 below. The emissions from the emergency response boat and survival craft are not included in Table 9.1.

Table 9.1
Point Arguello Source Limit
Supply Boat Emissions

	NOx	ROC	CO	SOx	PM	PM10
lbs/day	1,246.30	44.70	184.74	90.05	74.93	71.93
tons/year	76.25	3.99	16.67	8.18	6.79	6.51

(b) Operational Limits: Operation of the equipment listed in this section shall not exceed the limits listed below. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit.

(i) *Supply Boat Main Engine Limits:* The combined fuel use for all Point Arguello Project supply boat main engines shall not exceed: 1,967 gallons per day; 90,269 gallons per quarter; 361,254 gallons per year of diesel fuel.

(ii) *Supply Boat Auxiliary Engine Limits:* The combined fuel use for all Point Arguello Project supply boat auxiliary engines (generators and bow thruster) shall not exceed: 239 gallons per day; 9,784 gallons per quarter; 39,149 gallons per year of diesel fuel.

(iii) *Crew Boat Main Engine Limits*: The crew boat main engines serving Platform Hidalgo shall not use more than: 787 gallons per day; 2,361 gallons per quarter; 7.081 gallons per year of diesel fuel.

(iv) *Crew Boat Auxiliary Engine Limits:* The crew boat auxiliary engines serving Platform Hidalgo shall not use more than: 66 gallons per day; 132 gallons per quarter; 528 gallons per year of diesel fuel.

(v) *Emergency Response Boat Engine Limits:* The emergency response boat engines shall not use more than: 20,000 gallons per quarter; 80,000 gallons per year of diesel fuel. The permittee's pro-rated allocation of allowable emergency response boat fuel usage shall not exceed: 5,000 gallons per quarter; 20,000 gallons per year of diesel fuel.

(vi) Marine Survival Craft. The marine survival craft shall be limited to 200 hours of operation per year.

(vii) *Spot-Charter Limits*: The number of allowable annual spot charter crew boat trips shall not exceed one trip per year. The number of allowable annual spot charter supply boat trips shall not exceed ten-percent of the actual annual number of trips made by the controlled (i.e., primary) supply boats. A trip is defined as any time the boat makes a trip from port to the platform and back (i.e. a round trip).

(viii) *Liquid Fuel Sulfur Limit*: Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.0.0015 weight percent.

(ix) *New and Replacement Crew and Supply Boats*: The permittee may utilize any new/replacement project boat without the need for a permit revision if that boat meets the following conditions:

(1) The main engines are of the same or less bhp rating; and

(2) The combined pounds per day potential to emit (PTE) of all generator and bow thruster engines is the same or less than the sum of the pounds per day PTE for these engines as determined from the corresponding Table 5.1-3 emission line items of this permit; and

(3) The NO_x, ROC, CO, PM and PM10 emission factors are the same or less for the main and auxiliary engines. For the main engines, NO_x emissions must meet the 337 lb/1000 gallons emission standard.

The above criteria also apply to spot charter boats, except for the NO_x emission standard noted in (3) above. Any proposed new/replacement crew, supply or spot charter boat that does not meet the above requirements (1) - (3) shall first obtain a permit revision prior to operating the boat. The APCD may require manufacturer guarantees and emission source tests to verify this NO_x emission standard.

The permittee shall revise the Boat Monitoring and Reporting Plan, obtain APCD approval of such revisions and implement the revised Plan prior to bringing any new/replacement boat into service, except for the use of spot charters. If a new spot charter is brought into service then the permittee shall revise and resubmit the boat plan within thirty (30) calendar days after it is first brought into service. If the fuel metering and emissions computation procedures for a new spot charter are identical to a boat that is already addressed in the approved boat plan, a letter addendum stating this will suffice for the revision/resubmittal of the boat plan.

Prior to bringing the boat into service for the first time, the permittee shall submit the information listed below to the APCD for any new/replacement crew and supply boat that meets the requirements set forth in (a) - (c) above, and for new spot charters that have not been previously used on the Point Arguello project. For spot charters, this information shall be submitted within thirty (30) calendar days after the boat is first brought into service. The permittee shall notify the APCD (via fax or E-mail) within three (3) calendar days after a new spot charter is first brought into operation. Any boat put into service that does not meet the requirements above, as determined by the APCD at any time, shall immediately cease operations and all prior use of that boat shall be considered a violation of this permit.

- Boat description, including the type, size, name, engine descriptions and emission control equipment.
- Engine manufacturers' data on the emission levels for the various engines and applicable engine specification curves.
- A quantitative analysis using the operating and emission factor assumptions given in tables 5.1-1 and 5.1-2 of this permit that demonstrates criteria (b) above is met.
- Estimated fuel usage within 25-miles of Platform Hidalgo.
- Any other information the APCD deems necessary to ensure the new boat will operate consistent with the analyses that form the basis for this permit.

(x) *Availability of Maintenance Logs*: Upon request, the permittee shall make available to the APCD engine maintenance logs that include: details on injector timing, setting adjustments, major engine overhauls, and routine engine maintenance.

(c) Monitoring: PXP shall comply with the following requirements:

(i) *Boat Use Monitoring*: The permittee shall comply with the requirements of the APCD's *Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document (dated June 21, 1991 and any subsequent updates) for documenting and reporting boat activity, fuel usage and emissions associated with the platform. Boats reporting emissions based on cruise mode only shall not be required to comply with the protocol requirements for boat speed, engine rpm, mode or activity code. Further, the permittee's crew boat is not required to install fuel meters if the total permitted usage is eight trips per year or less.

The permittee shall implement the *Boat Monitoring and Reporting Plan*. This plan shall be used for measuring, calculating, and reporting fuel use and emissions for all boats servicing the Point Arguello Project. The data collected and reported shall demonstrate that the boats are being operated consistent with the emission assumptions used in the issuance of this operating permit. Spot charter boats shall, at a minimum, track total fuel usage on a per trip basis using APCD-approved procedures. Emergency response boats shall, at a minimum, track fuel usage on a quarterly basis using APCD-approved procedures. These data shall be submitted in an APCD-approved format to the APCD.

(ii) *Source Testing*: Source testing of the supply boat main engines shall occur on an annual basis. PXP shall perform source testing of air emissions and process parameters consistent with the requirement of the *Source Testing* permit condition below.

(d) Recordkeeping: The following records shall be maintained in legible logs and shall be made available to the APCD upon request:

(i) *Maintenance Logs:* Maintenance log summaries that include details on injector timing, setting adjustments, major engine overhauls, and routine engine maintenance. These logs and summaries shall be made available to the APCD upon request.

(ii) *Crew Boat Fuel Usage*: Daily, quarterly and annual fuel use for the crew boat main engines and auxiliary engines.

(iii) *Supply Boat Fuel Usage*: Daily, quarterly and annual fuel use for the supply boat main engines, generator engine and bow thruster engine.

(iv) *Emergency Response Boat Fuel Usage*: Total quarterly and annual fuel use for the emergency response boat and Platform Hidalgo's allocation of that total.

(v) *Spot Charters*: The name of each spot charter boat used and the number of round trips.

(vi) 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 PXP or certified by the fuel supplier.

(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 the *Semi-Annual Compliance Verification Reports* condition of this permit. [*Re: APCD Rule 1303, PTO 9105, ATC/PTO 9883, 40 CFR 70.6]*

C.6. **Pigging Equipment**: The following equipment are included in this emissions category:

EQ Device No.	Name
103175	Oil Pig Launcher
103176	Gas Pig Launcher

a) Emission Limits: Mass emissions from the oil and gas pig launchers listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in APCD Rule 325.E. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, PXP shall adhere to the following requirements that will be included in a *Pigging - Standard Operational Procedures* document..

(i) *Events*: The number of oil and gas pig operations (events) shall not exceed the maximum operating schedule listed in Table 5.1-1.

(ii) *Pressure*: The pig launchers shall be depressurized to the flare prior to each hatch opening to the maximum extent feasible, but at no time shall the pig launcher hatches be opened when the pressure in the launchers is greater than 1 psig. Pressure readings shall be recorded prior to each opening of the launchers.

(iii) *Openings*: Access openings to the pig launchers shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the launchers or during equipment inspection and maintenance. Prior to opening the pig launchers, the vessel shall be purged with either sweet fuel gas (not to exceed 50 ppmv total sulfur content calculated as H_2S at standard conditions), nitrogen or water.

(c) Monitoring: For all pigging events, pig launcher pressure shall be monitored by a pressure gauge at the pig launcher. Additionally, the APCD may request pig launcher gas sample analyses as necessary.

(d) Recordkeeping: PXP shall record in a log each pigging operation. The log shall include the date and pigging unit used (e.g., oil or gas) and the pressure gauge reading.

(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.6 (d) above.

[Re: APCD Rules 325 and 1303, PTO 9105-10;, 40 CFR 70.6]

C.7 **Tanks/Sumps/Separators:** The following equipment are included in this emissions category:

EQ Device No.	Name	KVB Service
Sumps And Wastewater Tanks		
005436	Produced Water Surge Tank (T-31)	Heavy Oil
005437	Disposal Pile (T-75)	Heavy Oil
005438	Sump Tank (T-72)	Heavy Oil
005439	Sump Deck Tank (T-74)	Heavy Oil
005440	Cutting Dewater Shaker (M-104)	Heavy Oil
005444	Oily Water Separator (M-70)	Heavy Oil
Oil/Water Separators		
--	Air Flotation Cell (M-31)	Heavy Oil
005442	CPI Separator (M-32)	Heavy Oil
005443	CPI Separator (M-33)	Heavy Oil

(a) Emission Limits: Mass emissions from the equipment listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.

(b) Operational Limits: Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, PXP shall:

(i) *VRS Use*: The vapor recovery systems 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 associated with each VRS system. Each VRS system shall be maintained and operated to minimize the release of emissions from all systems, including pressure relief valves and gauge hatches.

(ii) *Vapor Recovery System Efficiency*: The vapor recovery system shall maintain a minimum efficiency of 90-percent (mass basis).

(iii) *Air Flotation Cell*: The floatation cell unit shall not process more than 1.08 million gallons per day and 394.20 million gallons per year.

(iv) *CPI Separators*: Each CPI separator shall not process more than 0.54 million gallons per day and 197.10 million gallons per year.

(v) *Oily Water CPI Separator*: This unit, designated M-70, may only be used as an atmospheric wastewater sump and may not receive any primary production during normal operations. In the event of an emergency spill, M-70 may receive primary production to prevent crude oil being discharged into the disposal skim pile, T-75. PXP shall maintain records of all emergency events resulting in primary production being introduced into M-70. Emergency spill emissions for M-70 shall be quantified using the criteria for an oil/water separator as documented in Table N1. *[ATC/PTO 9946]*

(c) Temporary Use of Flotation Cell (Wemco) Replacements. The flotation cell may be replaced temporarily only if requirements (i - iv) listed below are satisfied.

(i) The permitted unit is in need of routine repair or maintenance.

(i) The permitted unit that is undergoing routine repair or maintenance is returned to its original service within 60 days of placement of the temporary unit. For good cause, and with advance written APCD approval, this time period may be extended.

(ii) The temporary unit has the same or lower potential to emit of each pollutant as the permitted flotation cell that is being temporarily replaced.

(iii) The temporary replacement unit shall comply with all rules and permit requirements that apply to the permitted unit that is undergoing routine repair or maintenance.

(iv) Within three days of temporarily replacing a permitted unit, the permittee shall notify the APCD project manager E-mail or fax. The notification shall include the date the temporary unit was installed, the specifications of the temporary flotation cell (Wemco unit), and the number of days anticipated for use.

(v) Within 14 days upon return of the original permitted unit to service, the permittee shall notify by E-mail or fax the APCD project manager of the date that the temporary unit was removed from the platform along with the highest daily (gallons/day) throughput for the temporary unit.

Any flotation cell (Wemco unit) in temporary replacement service shall be immediately shut down if the APCD determines that the requirements of this condition have not been met

(d) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of APCD Rule 325.H. The test methods outlined in APCD Rule 325.G shall be used, as applicable. In addition, PXP shall:

(i) Analyze the process streams listed the *Process Stream Sampling and Analysis* permit condition below.

(e) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in APCD Rule 325.F. In addition, PXP shall maintain logs for the information listed below. These logs shall be made available to the APCD upon request:

(i) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production

(ii) Process stream analyses data as required from the *Process Stream Sampling and Analysis* permit condition.

(iii) On a daily basis, the amount of oily water processed in the air flotation cell, any temporary air floatation cell and each CPI separator in units of gallons.

(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 the *Compliance Verification Reports* condition of this permit. [*Re: APCD Rules 325 and 1303, PTO 9105, 40 CFR 70.6*]

C.8 **Solvent Usage**: The following equipment are included in this emissions unit category:

EQ Device No.	Name
103116	Cleaning/Degreasing

(a) Emission Limits: Mass emissions from the solvent usage shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Compliance shall be based on the operational, recordkeeping and reporting requirements of this permit. For short-term emissions, compliance shall be based on monthly averages.

(b) Operational Limits: Use of solvents for cleaning, degreasing, thinning and reducing shall conform to the requirements of APCD Rules 317, 321 and 324. Compliance with these rules shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit and facility inspections. In addition, PXP shall comply with the following:

(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) *Reclamation Plan*: Any disposal of any reclaimed solvent shall be in accordance with the *PXP Solvent Reclamation Plan* . All solvent disposed of pursuant to the

Plan will have the appropriate solvent recovery factor applied for solvent use recordkeeping.

(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 readily accessible location on the platform.

(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 the *Compliance Verification Reports* condition of this permit. [*Re: APCD Rules 317, 321, 324 and 1303, PTO 9105, 40 CFR 70.6*]

C.9 **Helicopter Use**: The following equipment are included in this emissions unit category:

EQ Device No.	Name
103111	Helicopters

(a) Emission Limits: None.

(b) Operational Limits: None

(c) Monitoring: None

(d) Recordkeeping: Manual records shall be maintained for all helicopters. Records shall be maintained at a readily accessible location for a period of two years, and the APCD shall be notified of such location. The format of the manual records shall be as follows:

(i) Helicopter description, including the type, size, name, and home base.

(ii) Make, model and horsepower of engine.

(iii) Date, flight time, and segment description of each flight.

(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 the *Compliance Verification Reports* condition of this permit. The following shall be included in the report:

(i) Helicopter model.

(ii) Frequency and description of flight segment.

(iii) Total NOx and ROC emissions for each segment type, as well as total emissions for the reporting period. Helicopter emissions shall be calculated by multiplying the total number of each segment by the standard emissions per segment presented in Attachment 10.4 or other more representative emission factors. [*Re: PTO 9105 40 CFR 70.6*]

C.10 **Standby/Emergency Diesel IC Engines.** The following equipment are included in this emissions unit category:

Device ID #	Device Name
005060	IC Engine: Emergency Standby Generator (1250 bhp)
005063	IC Engine: Standby Fire Water Pump (517 (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. The emissions of PM and other pollutants shall not exceed the emissions standards listed in Table 2 of this permit. 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 C.1(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[9], have no operational hours limitations.

(i) *Maintenance & Testing Use Limit:* Effective January 1, 2006, the stationary emergency standby diesel-fueled CI engine(s) subject to this permit, shall limit maintenance and testing[10] operations to no more than 2 hours per day and 200 hours per year.

(ii) *Fuel and Fuel Additive Requirements:* Effective January 1, 2006, 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

[9] 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

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

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.

C.11 **Offsets -** PXP shall comply with the procedures and requirements specified in Section 7.3 (Offset Requirements) and offset all planned flaring emissions of SO_x (as SO_2) for flare gas compositions exceeding 239 ppmvd (as H_2S). Emission Reduction Credits (ERCs) sufficient to offset the annual SO_x emissions as specified in Table 7.3-1 shall be in place for the life of the project.

C.12 **Offsets - Platform Hidalgo Flare Gas Sulfur Increase Project**: PXP shall offset all sulfur oxides (SO_x) emissions pursuant to Table 7.3-2 that result from the Platform Hidalgo gas flare sulfur increase project. Emission reduction credits (ERCs) sufficient to offset the permitted quarterly SO_x emissions shall be in place for the life of the flare sulfur increase project.

C.13 **Facility Throughput Limitations:** Platform Hidalgo production shall be limited to a monthly average of 35,000 barrels of oil emulsion[11] per day and 18 million standard cubic feet of produced gas per day. PXP shall record in a log the volumes of oil emulsion and gas produced and the actual number of days in production per month. The above limits are based on actual days of operation during the month. [*Re: PTO 9105*]

C.14 **Produced Gas:** PXP shall direct all produced gases to the sales compressors, the flare header or other permitted control device when de-gassing, purging or blowing down any oil and gas well or

[11] Oil emulsion is defined as the total amount of crude oil and water produced from the wells.

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 (e.g., well spikes), well blow down and MMS ordered safety tests. [*Re: APCD Rules 325, 331, PTO 9105*]

C.15 **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 implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. PXP shall implement their *IC Engine Particulate Matter Operation and Maintenance Plan* for the life of the project. 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 project diesel-fired engines, regardless of exemption status, shall be included in this Plan. [*Re: APCD Rules 205.A, 302, 304, 309, PTO 9105*]

C.16 **Abrasive Blasting Equipment:** All abrasive blasting activities performed on Platform Hidalgo shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. [*Re: APCD Rules 303, PTO 9105*]

C.17 **Process Monitoring Systems - Operation and Maintenance:** All platform process monitoring devices listed in Section 4.10 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. PXP shall implement their *Process Monitor Calibration and Maintenance Plan* for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment is utilized. [*Re: PTO 9105*]

C.18 **Source Testing**: The following source testing provisions shall apply:

(a) The permittee shall conduct source testing of air emissions and process parameters listed in Table 4.1 of this Permit to Operate. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCO, occur.

- Source testing of the supply boat main engines shall occur on an annual basis. The supply boat engines shall be tested at normal cruise speeds (minimum of 70-percent of maximum engine load).

- Source testing of the crane engines shall be performed on a biennial schedule. The crane engines shall be loaded to the maximum safe load obtainable.

- Source testing of the turbines shall be conducted on an annual basis. During each annual source test, one turbine shall be tested while operating at maximum load and the remaining three turbines will be tested at "historical" based on the prior year's usage. The turbine tested at maximum load for subsequent annual tests will rotate to each turbine with the remaining turbines being tested at "historical" loads.

Exceptions, as described in Condition 9.C.2, from annual turbine source testing shall apply to this permit.

(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. [*Re: PTO 9105, PTO 10206*]

C.19 **Process Stream Sampling and Analysis:** PXP shall sample and analyze the process streams listed in Section 4.12 of this permit according to the methods and frequency detailed in that Section. All process stream samples shall be taken according to APCD approved ASTM methods and must follow traceable chain of custody procedures. [*Re: APCD Rules 325, 331, 333, PTO 9105*]

C.20 **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 platform. These records or logs shall be readily accessible and be made available to the APCD upon request. [*Re: APCD Rule 1303, PTO 9105, 40 CFR 70.6*]

C.21 **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 1st. The second report shall cover calendar quarters 3 and 4 (July through December) and shall be submitted no later than March 1st. 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, the annual report shall include a completed *APCD Annual Emissions Inventory* questionnaire. The report shall include the following information:

(a) *Internal Combustion Engines.*

(i) The daily, quarterly and annual fuel use for each pedestal crane and turbine starter engine in units of gallons, and resultant mass emissions for each.

(ii) The monthly and cumulative annual hours of operation for each turbine starter engine.

(iii) The monthly and cumulative annual hours of operation for the fire water pump and the emergency power generator (by ID number), and resultant mass emissions for each.

(iv) Description of any temporary equipment, including type and horsepower. The amount and type of fuel consumed per month (for equipment using fuel as a basis for emission calculations) and the number of hours each equipment item operated each month, and resultant mass emissions for each.

(v) Results of the quarterly Rule 333 portable NO_x analyzer readings.

(vi) Total sulfur content of each diesel fuel shipment. Annually, the higher heating value of the diesel fuel (Btu/gal).

(vii) Summary results of all compliance emission source testing performed.

(viii) For Standby/Emergency Diesel IC Engines:
(a) emergency use hours of operation;
(b) maintenance and testing hours of operation
(c) 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.

(d) written statement from fuel supplier if provided in lieu of fuel use records.

(b) *Turbines:* PXP shall provide daily and monthly summaries of each parameter listed below for each turbine. These summaries shall include the average daily values for each process parameter specified, and the total NO_x and ROC emissions for each day of the calendar month. In addition, the summary shall include the daily hours of operation for turbines G-91, G-92 and G-93 with the W/F ratios less than those specified in Condition 9.C.2. Reports for turbine G-94 shall contain a quarterly summary (by calendar quarter) of the chronological three-minute data at operating loads below 1,200 kW, including "run status" (i.e., starting, stopping, or running), as well as the same data sorted first by run status and then in ascending load.

(i) Date and time of reading.

(ii) Kilowatts (generators only).

(iii) Fuel rate, including diesel (generators only) and the fuel gas.

(iv) Water rate.

(v) For each turbine, requiring water injection the total cumulative time for each quarter that the water to fuel ratio fell below 0.80, the total cumulative time water was required to be injected. and the annual (calendar) percentage of time that water was injected while the turbines operated above 650 kw.

(vi) Mass emissions for each turbine.

(vii) Summary results of all compliance emission source testing performed.

(viii) ADGS failures and downtime. PXP shall report the reasons for the ADGS system failures and the measures taken to correct each failure. Emissions during ADGS downtime shall be determined by using the average hourly emission rate (determined by dividing the total emissions by the actual operating time during which the ADGS was operational for that calendar quarter), times the number of hours of ADGS downtime.

(c) *Flare.*

(i) The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge/Pilot; Planned - Continuous; Planned - Other; Unplanned), shall be presented as a cumulative summary for each day, quarter and year.

(ii) The sulfur content (ppm_v) for each planned (continuous) flaring event.

(iii) A listing of all infrequent flaring events that exceed 4 events per year from the same cause from the same processing unit or equipment type.

(iv) The highest total sulfur content and hydrogen sulfide content observed each week in the flare header.

(v) The monthly total sulfur content of flare purge and pilot fuel gas.

(d) *Fugitive Hydrocarbons*: Rule 331/Enhanced Monitoring fugitive hydrocarbon I&M program data (on a quarterly basis):

(i) Inspection summary.

(ii) Record of leaking components.

(iii) Record of leaks from critical components.

(iv) Record of leaks from components that incur five repair actions within a continuous 12-month period.

(v) Record of component repair actions including dates of component re-inspections.

(vi) An updated FHC I&M inventory due to change in component list or diagrams.

(vii) Mass emissions from fugitive hydrocarbons.

(viii) Listing of components installed as BACT under APCD Rule 331 as approved by the APCD.

(e) *Crew and Supply Boats:*

(i) Daily, quarterly and annual fuel use for the crew boat main engines and auxiliary engines while operating within 25-miles of Platform Hidalgo, itemized by regular crew boat (controlled ICE) usage and spot charter/emergency response boat (uncontrolled ICE) usage, and resultant mass emissions for each.

(ii) Daily, quarterly and annual fuel use for the supply boat main engines and auxiliary engines while operating within 25-miles of Platform Hidalgo, itemized by regular supply boat (controlled ICE) usage and spot charter/emergency response boat (uncontrolled ICE) usage, and resultant mass emissions for each.

(iii) The sulfur content of each delivery of diesel fuel used by the crew and supply boats.

(iv) Information regarding any new project boats servicing PXP's OCS platforms as detailed in Permit Condition 9.C.5 above.

(v) If requested by the APCD staff, maintenance log summaries including details on injector type and timing, setting adjustments, major engine overhauls, and routine engine tune-ups. For spot charters this shall be provided as available.

(vi) The number of boat trips made (a) by the crew and supply boats and (b) by the spot charter (crew and supply) boats, both itemized by the trip dates and the boat names.

(vii) Summary results of all compliance emission source testing performed.

(f) *Pigging*: For each pig receiver and launcher, the number of pigging events per day, quarter and year and resultant mass emissions.

(g) *Tanks/Sumps/Separators*:

(i) On a daily basis, the amount of oily water processed in each floatation cell unit, in units of gallons.

(h) *Helicopters.*

(i) Helicopter model.

(ii) Frequency and description of flight segment.

(iii) Total NOx and ROC emissions for each segment type, as well as total emissions for the reporting period.

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

(j) *General Reporting Requirements*:

(i) On a monthly basis, the total oil emulsion and produced gas production along with the number of days per month of production.

(i) On quarterly basis, the emissions from each permitted emission unit for each criteria pollutant.

(ii) On quarterly basis, the emissions from each exempt emission unit for each criteria pollutant.

(iii) On quarterly basis, PXP shall submit data for CEM downtime and CEM detected excess emissions in a format approved by the APCD.

(iv) A summary of each and every occurrence of non-compliance with the provisions of this permit, APCD rules, and any other applicable air quality requirement.

(v) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by condition 9.C.19 of this permit. Process stream analyses per Section 4.12.

(vi) Breakdowns and variances reported/obtained per Regulation V along with the excess emissions that accompanied each occurrence

(vii) Helicopter trips (by type and trip segments with emission calculations)

(viii) On an annual basis, the ROC and NO_x emissions from all permit exempt activities.

(ix) Tons per quarter totals of all pollutants (by each emission unit). The third/fourth quarter report shall include tons per year totals for all pollutants (by each emission unit).

(x) A copy of the Rule 202 De Minimis Log for the stationary source. [*Re: PTO 9105*]

C.22 **Emergency Episode Plan**: PXP shall implement the most recently issued version of the APCD-approved Emergency Episode Plan during emergency episodes. [*Re: APCD Rule 1303, PTO 91054*]

C.23 **Permitted Equipment:** Only those equipment items listed in Attachment 10.3 are covered by the requirements of this permit and APCD Rule 201.B. [*Re: APCD Rule 1303, PTO 9105*]

C.24 **Mass Emission Limitations**: Mass emissions for each equipment item (i.e., emissions unit) associated with Platform Hidalgo shall not exceed the values listed in Tables 5.1-3 and 5.1-4. Emissions for the entire facility shall not exceed the total limits listed in Table 5.2. [*Re: APCD Rule 1303, PTO 9105, 40 CFR 70.6*]

C.25 **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) *Purging and Inerting Procedures Plan (approved December 2002)*

b) *Boat Monitoring and Reporting Plan (approved September 2002)*

c) *Rule 333 Inspection and Maintenance Plan (approved September 2002)*

d) *Turbine ADGS Quality Assurance Plan (approved September 2002)*

e) *Rule 359 Flare Minimization Plan (approved September 2002)*

f) *Fugitive I&M Plan (approved September 2002)*

g) *Diesel IC Engine Particulate Matter Operation and Maintenance Plan (approved September 2002)*

h) *Process Monitor Calibration and Maintenance Plan (approved December 2002)* *i)* <u>*Fuel Gas Sulfur Reporting Plan (approved December 2002)*</u>

j) <u>*Flare Gas Sulfur Reporting Plan (approved December 2002)*</u>

k) <u>*Source Test Plan (approved February 2001)*</u>

l) <u>*Emergency Episode Plan (approved February 2005)*</u>

9.D *APCD-Only Conditions*

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

→ There are no permit conditions that are APCD-only enforceable for this permit ←

AIR POLLUTION CONTROL OFFICER

____

____
Date

<u>Notes</u>:

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.

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

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.

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

- 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:

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

- 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:

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

- 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:

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

- 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).

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

- 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 (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.

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

- 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

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

- 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:

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

- 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		

AN UPDATED VERSION OF THIS TABLE WILL BE PROVIDED. (GOHF EMISSION HAVE NOT BEEN REVISED).

Table 10.2-4

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

Facility	NO_x	ROC	CO	SO_x	TSP	PM_{10}
Gaviota Plant						
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, February 14, 2008
Santa Barbara County APCD – Equipment List

PT-70/Reeval 09105 R3 / FID: 08015 Platform Hidalgo / SSID: 01325

A PERMITTED EQUIPMENT

1 Main Engines

Device ID # 005430 Device Name Main Engines

Rated Heat Input Physical Size 1530.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Three main engines at 510 bhp each.

2 Pumps

2.1 Oil Shipping Pump

Device ID # 103134 Device Name Oil Shipping Pump

Rated Heat Input Physical Size 450.00 Horsepower (Electric Motor)
Manufacturer Worthington Operator ID E-SB-00-1800-5
Model NJSHP Serial Number P-1
Location Note Wellhead deck
Device Description Pumps crude oil, rated capacity 377 gpm, powered by 450 hp electric motor.

2.2 Oil Shipping Pump (spare)

Device ID # 103135 Device Name Oil Shipping Pump (spare)

Rated Heat Input Physical Size 450.00 Horsepower (Electric Motor)
Manufacturer Worthington Operator ID E-SB-00-1800-5
Model NJSHP Serial Number P-2
Location Note Wellhead deck
Device Description Pumps crude oil, rated capacity 377 gpm, powered by 450 hp electric motor.

2.3 Oil Charge Pump

Device ID # 103136 Device Name Oil Charge Pump

Rated Heat Input Physical Size 200.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model 1450VLT Serial Number P-4
Location Note Wellhead deck
Device Description Pumps crude oil, rated capacity 564 gpm, powered by 200 hp electric motor.

2.4 Oil Charge Pump

Device ID # 103137 Device Name Oil Charge Pump

Rated Heat Input Physical Size 200.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model 1450VLT Serial Number P-5
Location Note Wellhead deck
Device Description Pumps crude oil, rated capacity 564 gpm, powered by 200 hp electric motor.

2.5 Oil Charge Pump

Device ID # 103138 Device Name Oil Charge Pump

Rated Heat Input Physical Size 200.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model 1450VLT Serial Number P-6
Location Note Wellhead deck
Device Description Pumps crude oil, rated capacity 564 gpm, powered by 200 hp electric motor.

2.6 Oil Shipping Pump

Device ID # 103139 Device Name Oil Shipping Pump

Rated Heat Input Physical Size 600.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model 3X6X9CMX Serial Number P-7
Location Note Wellhead deck
Device Description Pups crude oil, rated capacity 564 gpm, powered by 600 hp electric motor.

2.7 Oil Shipping Pump

Device ID # 103140 Device Name Oil Shipping Pump

Rated Heat Input Physical Size 600.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model 3X6X9CMX Serial Number P-8
Location Note Wellhead deck
Device Description Pumps crude oil, rated at 564 gpm, powered by 600 hp electric motor.

2.8 Glycol Circulation Pump

Device ID # 103141 Device Name Glycol Circulation Pump

Rated Heat Input Physical Size 3.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model P-100A Serial Number P-10
Location Note Wellhead deck
Device Description In circulation service, pumps glycol, rated capacity 3 gpm, powered by 3 hp electric motor.

2.9 Glycol Circulation Pump

Device ID # 103142 Device Name Glycol Circulation Pump

Rated Heat Input Physical Size 3.00 Horsepower (Electric Motor)
Manufacturer Byron-Jackson Operator ID E-SB-00-1800-5
Model P-100A Serial Number P-11
Location Note Wellhead deck
Device Description In circulation service, pumps glycol, rated capacity 3 gpm, powered by 3 hp electric motor.

2.10 Amine Circulation Pump

Device ID # 103143 Device Name Amine Circulation Pump

Rated Heat Input Physical Size 50.00 Horsepower (Electric Motor)
Manufacturer Sundstrand Operator ID E-SB-00-1800-5
Model LMV-322 Serial Number P-12
Location Note Wellhead deck
Device Description In circulation service, pumps lean amine, rated capacity 65 gpm, powered by 50 hp electric motor.

2.11 Amine Circulation Pump

Device ID # 103144 Device Name Amine Circulation Pump

Rated Heat Input Physical Size 50.00 Horsepower (Electric Motor)
Manufacturer Sundstrand Operator ID E-SB-00-1800-5
Model LMV-322 Serial Number P-13
Location Note Wellhead deck
Device Description In circulation service, pumps lean amine, rated capacity 65 gpm, powered by 50 hp electric motor.

2.12 High Pressure Relief Condensate Pump

Device ID # 103145 Device Name High Pressure Relief Condensate Pump

Rated Heat Input Physical Size 30.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Operator ID E-SB-00-1800
Model G-S1 Serial Number P-14
Location Note Wellhead deck
Device Description Pumps condensate, rated capacity 50 gpm, powered by 30 hp electric motor.

2.13 Amine Reflux Pump

Device ID # 103105 Device Name Amine Reflux Pump

Rated Heat Input Physical Size
Manufacturer Union Pumps Operator ID E-SB-00-1800-5
Model Serial Number
Location Note Wellhead deck
Device Description

2.14 High Pressure Relief Condensate Pump

Device ID # 103146 Device Name High Pressure Relief Condensate Pump

Rated Heat Input Physical Size 30.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Operator ID E-SB-00-1800-5
Model G-S1 Serial Number P-15
Location Note Wellhead deck
Device Description Pumps condensate, rated capacity 50 gpm, powered by 30 hp electric motor.

2.15 Amine Reflux Pump

Device ID # 103147 Device Name Amine Reflux Pump

Rated Heat Input Physical Size 5.00 Horsepower (Electric Motor)
Manufacturer Union Pumps Operator ID E-SB-00-1800-5
Model Serial Number P-16
Location Note Wellhead deck
Device Description In circulation service, pumps amine, rated capacity 12.4 gpm, powered by 5 hp electric motor.

2.16 Heat Medium Pump

Device ID # 103148 Device Name Heat Medium Pump

Rated Heat Input Physical Size 200.00 Horsepower (Electric Motor)
Manufacturer Operator ID
Model Serial Number P-92
Location Note wellhead deck/prod. module
Device Description Pumps Caloria HT-42, rated capacity 1500 gpm, powered by 200 hp electric motor.

2.17 Heat Medium Pump

Device ID # 103149 Device Name Heat Medium Pump

Rated Heat Input Physical Size 200.00 Horsepower (Electric Motor)
Manufacturer Operator ID
Model Serial Number P-93
Location Note Wellhead deck/prod. module
Device Description Pumps Caloria HT-42, rated capacithy 1500 gpm, powered by 200 hp electric motor.

2.18 Auxiliary Heat Medium Pump

Device ID # 103150 Device Name Auxiliary Heat Medium Pump

Rated Heat Input Physical Size 30.00 Horsepower (Electric Motor)
Manufacturer Operator ID
Model Serial Number P-94
Location Note wellhead deck\prod. module
Device Description Pumps Caloria HT-42, rated capacity 620 gpm, powered by 30 hp electric motor.

2.19 Produced Water Circulation Pump

Device ID # 103151 Device Name Produced Water Circulation Pump

Rated Heat Input Physical Size 25.00 Horsepower (Electric Motor)
Manufacturer Worthington Operator ID E-SB-00-1800-5
Model D-1131 Serial Number P-30
Location Note Wellhead deck
Device Description In recirculation service, pumps produced water, rated at 935 gpm, powered by 25 hp electric motor.

2.20 Produced Water Circulation Pump

Device ID # 103152 Device Name Produced Water Circulation Pump

Rated Heat Input Physical Size 25.00 Horsepower (Electric Motor)
Manufacturer Worthington Operator ID E-SB-00-1800-5
Model D-1131 Serial Number P-31
Location Note Wellhead deck
Device Description In recirculation service, pumps produced water, rated capacity 935 gpm, powered by 25 hp electric motor.

2.21 Produced Water Sand Pump

Device ID # 103153 Device Name Produced Water Sand Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-00-1800-5
Model LB2X4-14 Serial Number P-33
Location Note Wellhead deck
Device Description In transfer service, pumps produced water and sand, rated capacity 150 gpm, powered by 20 hp electric motor.

2.22 Produced Water Sand Pump

Device ID # 103154 Device Name Produced Water Sand Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-00-1800-5
Model LB2X4-14 Serial Number P-34
Location Note Wellhead deck

Device Description In transfer service, pumps produced water and sand, rated capacity 150 gpm, powered by 20 hp electric motor.

2.23 Jet Water Pump

Device ID # 103155 Device Name Jet Water Pump

Rated Heat Input Physical Size 75.00 Horsepower (Electric Motor)
Manufacturer Sundstrand Operator ID E-SB-00-1800-5
Model LMV-801 Serial Number P-35
Location Note Wellhead deck
Device Description In transfer service, pumps produced water, rated capacity 140 gpm, powered by 75 hp electric motor.

2.24 Jet Water Pump

Device ID # 103156 Device Name Jet Water Pump

Rated Heat Input Physical Size 75.00 Horsepower (Electric Motor)
Manufacturer Sundstrand Operator ID E-SB-00-1800-5
Model LMV-801 Serial Number P-36
Location Note Wellhead deck
Device Description In transfer service, pumps treated produced water, rated capacity 140 gpm, powered by 75 hp electric motor.

2.25 Air Flotation Skim Pump

Device ID # 103157 Device Name Air Flotation Skim Pump

Rated Heat Input Physical Size 5.00 Horsepower (Electric Motor)
Manufacturer U.S. Filter Operator ID E-SB-00-1800-5
Model Serial Number P-40
Location Note Wellhead deck
Device Description In circulation service, pumps produced water, rated capacity 120 gpm, powered by 5 hp electric motor.

2.26 Air Flotation Skim Pump

Device ID # 103158 Device Name Air Flotation Skim Pump

Rated Heat Input Physical Size 5.00 Horsepower (Electric Motor)
Manufacturer U.S. Filter Operator ID E-SB-00-1800-5

Model Serial Number P-41
Location Note Wellhead deck
Device Description In circulation service, pumps produced water, rated capacity 120 gpm, powered by 5 hp electric motor.

2.27 Production Drain Pump

Device ID # 103159 Device Name Production Drain Pump

Rated Heat Input Physical Size 15.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Operator ID E-SB-00-1900-4
Model 4FDFSISSQDAA Serial Number P-70
Location Note Sump deck
Device Description In drainage service, pumps produced water, rated capacity 50 gpm, powered by 15 hp electric motor.

2.28 Production Drain Pump (spare)

Device ID # 103160 Device Name Production Drain Pump (spare)

Rated Heat Input Physical Size 15.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Operator ID E-SB-00-1900-4
Model 4FDFSISSQDAA Serial Number P-71
Location Note Sump deck
Device Description Pumps produced water, rated at 50 gpm, powered by 15 hp electric motor.

2.29 Low Volume Sump Pump

Device ID # 103161 Device Name Low Volume Sump Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Operator ID E-SB-00-1900-4
Model 2GOGSISSQDAA Serial Number P-72
Location Note Sump deck
Device Description Pumps produced water, rated capacity 100 gpm, powered by 20 hp electric motor.

2.30 High Volume Sump Pump

Device ID # 103162 Device Name High Volume Sump Pump

Rated Heat Input Physical Size 10.00 Horsepower (Electric Motor)
Manufacturer Worthington Operator ID E-SB-00-1900-4
Model D-1131 Serial Number P-73
Location Note Sump deck
Device Description From drain sump, pumps dirty oil, rated capacity 300 gpm, powered by 10 hp electric motor.

2.31 Dirty Oil Transfer Pump

Device ID # 103163 Device Name Dirty Oil Transfer Pump

Rated Heat Input Physical Size 40.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Moyno Operator ID E-SB-00-1800-5
Model 6HOGAI SSQ DAA Serial Number P-74
Location Note Wellhead deck
Device Description In transfer service, pumps dirty oil, rated capacity 80 gpm, powered by 40 hp electric motor.

2.32 Dirty Oil Drain Pump

Device ID # 103164 Device Name Dirty Oil Drain Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-00-1800-5
Model LB2X4-14 Serial Number P-76
Location Note Wellhead deck
Device Description Pumps dirty oil, rated capacity 150 gpm, powered by 20 hp electric motor.

2.33 Oily Water Sand Pump

Device ID # 103165 Device Name Oily Water Sand Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-02-1291-4
Model LB2X4-14 Serial Number P-77
Location Note Wellhead deck
Device Description In BS&W service, pumps oily water and sand, rated capacity 150 gpm, powered by 20 hp electric motor.

2.34 Oily Water Sand Pump

Device ID # 103166 Device Name Oily Water Sand Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-02-1291-4
Model LB2X4-14 Serial Number P-78
Location Note Wellhead deck
Device Description In BS&W service, pumps oily water and sand, rated capacity 150 gpm, powered by 20 hp electric motor.

2.35 Dirty Oil Drain Pump

Device ID # 103167 Device Name Dirty Oil Drain Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-00-1800-5
Model Serial Number P-79
Location Note Wellhead deck
Device Description Pumps dirty oil, rated capacity 150 gpm, powered by 20 hp electric motor.

2.36 Dirty Oil Transfer Pump

Device ID # 103168 Device Name Dirty Oil Transfer Pump

Rated Heat Input Physical Size 40.00 Horsepower (Electric Motor)
Manufacturer Robbins & Meyers Moyno Operator ID E-SB-01-1191-4
Model 6HOGAI SSQ DAA Serial Number P-80
Location Note Wellhead deck
Device Description Pumps dirty oil, rated capacity 80 gpm, powered by 40 hp electric motor.

2.37 Production Drain Sand Pump

Device ID # 103169 Device Name Production Drain Sand Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Goulds Operator ID E-SB-00-1900-4
Model LB2X4-14 Serial Number P-81
Location Note Sump deck
Device Description In BS&W service, rated capacity 150 gpm, powered by 20 hp electric motor.

2.38 Diesel Transfer Pump

Device ID # 103170 Device Name Diesel Transfer Pump

Rated Heat Input Physical Size 7.50 Horsepower (Electric Motor)
Manufacturer Union Operator ID E-SB-00-1900-4
Model 1½" X 2 X 8 VLM Serial Number P-96
Location Note Sump deck
Device Description Pumps diesel fuel, rated capacity 27.5 gpm, powered by 7.5 hp electric motor.

2.39 Diesel Transfer Pump (spare)

Device ID # 103171 Device Name Diesel Transfer Pump (spare)

Rated Heat Input Physical Size 7.50 Horsepower (Electric Motor)
Manufacturer Union Operator ID E-SB-00-1900-4
Model 1½" X 2 X 8 VLM Serial Number P-97
Location Note Sump deck
Device Description Pumps diesel fuel, rated capacity 27.5 gpm, powered by 27.5 hp electric motor.

2.40 Diesel Pump (spare)

Device ID # 103172 Device Name Diesel Pump (spare)

Rated Heat Input Physical Size 5.00 Horsepower (Electric Motor)
Manufacturer Roper Operator ID E-SB-00-1900-4
Model 6721 Serial Number P-98
Location Note Sump deck
Device Description Pumps diesel fuel, rated capacity 25 gpm, powered by 5 hp electric motor.

2.41 Auxiliary Heat Medium Pump

Device ID # 103174 Device Name Auxiliary Heat Medium Pump

Rated Heat Input Physical Size 30.00 Horsepower (Electric Motor)
Manufacturer Operator ID
Model Serial Number P-95
Location Note wellhead deck/prod. module
Device Description Pumps Caloria HT-42, rated capacity 629 gpm, powered by 30 hp electric motor.

3 Gas/Condensate Service Components - Accessible

Device ID # 103108 Device Name Gas/Condensate Service Components - Accessible

Rated Heat Input Physical Size 4286.00 Component Leakpath
Manufacturer Operator ID 200
Model Serial Number
Location Note Various locations on Platform
Device Description

4 Main Gas Compressor

Device ID # 103132 Device Name Main Gas Compressor

Rated Heat Input Physical Size 3015.00 Horsepower (Electric Motor)
Manufacturer Worthington Compressor Co. Operator ID E-SB-03-1391-3
Model Supercub 6XH-6 Serial Number K-12
Location Note Wellhead
Device Description In produced gas and vapor recovery service, compressor rated at 2754 bhp and 10,349 scfm. Powered by 3015 hp electric motor.

5 Generator Engines

Device ID # 005431 Device Name Generator Engines

Rated Heat Input Physical Size 218.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Two genset engines at 109 bhp each, uncontrolled for NOx.

6 Air Flotation Cell

Device ID # 005441 Device Name Air Flotation Cell

Rated Heat Input Physical Size 750.00 gal/Minute
Manufacturer U.S. Filter Operator ID E-SB-00-1800-5
Model Serial Number M-31
Location Note Wellhead deck
Device Description Covered and connected to vapor recovery (control efficiency 95%).

Throughput: 1.08 mmgal/day; 98.6 mmgal/qtr; 394.2 mmgal/yr.

7 Turbines

7.1 Turbine Generator (G-91)

Device ID # 005069 Device Name Turbine Generator (G-91)

Rated Heat Input 40.820 MMBtu/Hour Physical Size 2800.00 Kilowatts
Manufacturer Solar-Centaur Operator ID E-SB-00-1600-4
Model T-4000 Serial Number G-91
Location Note Main deck
Device Description Fuel type Fuel gas/Diesel
Engine type Turbine/Turbine
Fuel higher heating value 1361.3/19,620
Units for fuel HHV Btu/ft3/Btu/lb
Total sulfur content of fuel 50/0.29
Units for sulfur content ppm/% wt
Operating hours per day (max.) 24/24
Operating hours per quarter (max.) 2190/875
Operating hours per year (highest annual average)
8760/1750
Emission controls used? Yes/Yes
Emission controls description Water injection/Water injection
Water/fuel injection rate 0.8:1/0.8:1
Ammonia/NOx inlet injection rate None/None
Backup fuel used? Yes/Yes

7.2 Turbine Generator (G-92)

Device ID # 005070 Device Name Turbine Generator (G-92)

Rated Heat Input 40.820 MMBtu/Hour Physical Size 2800.00 Kilowatts
Manufacturer Solar-Centaur Operator ID E-SB-00-1600-4
Model T-4000 Serial Number G-92
Location Note Main deck
Device Description Fuel type Fuel gas/Diesel
Engine type Turbine/Turbine
Fuel higher heating value 1361.3/19,620
Units for fuel HHV Btu/ft3/Btu/lb
Total sulfur content of fuel 50/0.29
Units for sulfur content ppm/% wt
Operating hours per day (max.) 24/24
Operating hours per quarter (max.) 2190/875
Operating hours per year (highest annual average)
8760/1750
Emission controls used? Yes/Yes
Emission controls description Water injection/Water injection
Water/fuel injection rate 0.8:1/0.8:1

Ammonia/NOx inlet injection rate None/None
Backup fuel used? Yes/Yes

7.3 Turbine Generator (G-93)

Device ID # 005071 Device Name Turbine Generator (G-93)

Rated Heat Input 40.820 MMBtu/Hour Physical Size 2800.00 Kilowatts
Manufacturer Solar-Centaur Operator ID E-SB-00-1600-4
Model T-4000 Serial Number G-93
Location Note Main deck
Device Description Fuel type Fuel gas/Diesel
Engine type Turbine/Turbine
Fuel higher heating value 1361.3/19,620
Units for fuel HHV Btu/ft3/Btu/lb
Total sulfur content of fuel 50/0.29
Units for sulfur content ppm/% wt
Operating hours per day (max.) 24/24
Operating hours per quarter (max.) 2190/875
Operating hours per year (highest annual average)
8760/1750
Emission controls used?Yes/Yes
Emission controls description Water injection/Water injection
Water/fuel injection rate 0.8:1/0.8:1
Ammonia/NOx inlet injection rate None/None
Backup fuel used? Yes/Yes

7.4 Turbine Generator (G-94)

Device ID # 005072 Device Name Turbine Generator (G-94)

Rated Heat Input 40.820 MMBtu/Hour Physical Size 2800.00 Kilowatts
Manufacturer Solar-Centaur Operator ID E-SB-00-1600-4
Model T-4700 Serial Number G-94
Location Note Main deck
Device Description Fuel type Fuel gas/Diesel
Engine type Turbine/Turbine
Fuel higher heating value 1361.3/19,620
Units for fuel HHV Btu/ft3/Btu/lb
Total sulfur content of fuel 50/0.29
Units for sulfur content ppm/% wt
Operating hours per day (max.) 24/24
Operating hours per quarter (max.) 2190/875
Operating hours per year (highest annual average)
8760/1750
Emission controls used?Yes/Yes

Emission controls description Water injection/Water injection
Water/fuel injection rate 0.8:1/0.8:1
Ammonia/NOx inlet injection rate None/None
Backup fuel used? Yes/Yes

8 Main Gas Compressor (spare)

Device ID # 103133 Device Name Main Gas Compressor (spare)

Rated Heat Input Physical Size 3015.00 Horsepower (Electric Motor)
Manufacturer Worthington Compressor Co Operator ID E-SB-03-1391-3
Model Supercub 6XH-6 Serial Number K-13
Location Note Wellhead
Device Description In produced gas and vapor recovery service, compressor rated at 2754 bhp and 10,349 scfm. Powered by 3015 hp electric motor.

9 Oil Service Components - Accessible

Device ID # 103244 Device Name Oil Service Components - Accessible

Rated Heat Input Physical Size 7113.00 Component Leakpath
Manufacturer Operator ID
Model Serial Number
Location Note Various locations on Platform
Device Description

10 Spot Charter Boat Engines

Device ID # 105092 Device Name Spot Charter Boat Engines

Rated Heat Input Physical Size 1530.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Total 1530 bhp main engines, uncontrolled for NOx.

11 Wellheads

11.1 Oil and Gas Wellheads

Device ID # 103245 Device Name Oil and Gas Wellheads

Rated Heat Input Physical Size 11.00 Active Wells
Manufacturer Operator ID
Model Serial Number
Location Note Wellhead deck
Device Description No plugged and abandoned oil and gas wells, no gas injection wells, no water injection wells.

The Device Grouping Number is represented by a Chevron USA drawing number.

Well numbers: C1, C2, C3, C4, C5, C7, C8, C9, C10, C11.

12 Helicopters

12.1 Helicopter

Device ID # 103111 Device Name Helicopter

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Location Note SMA to Platforms
Device Description Manufacturer Sykorski Helicopters
Model Number SK-76

See permit for trip details.

13 Maintenance Supply

Device ID # 103115 Device Name Maintenance Supply

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Location Note Platform Hidalgo
Device Description Coating/solvent brand name MEK
Application Solvent
Annual usage (gal per year) 150
Regulatory VOC content (g/l) na
ROC emission factor (lb/gal) 6.7
Emission controls used?Yes
Emission controls description Product recycled

14 Oily Water CPI Separator

Device ID # 103246 Device Name Oily Water CPI Separator

Rated Heat Input Physical Size
Manufacturer Pace Setter Operator ID E-SB-00-1700-4
Model Serial Number M-70
Location Note Mezzanine deck
Device Description Use as oil/water separator for emergency oil spill containment only (see PTO Mod 9105-04 Condition 37) Covered; not connected to vapor recovery.

Throughput: 0.58 mmgal/day; 52.6 mmgal/qtr; 210.2 mmgal/yr.

15 Stationary Internal Combustion Engines

15.1 IC Engine: East Crane

Device ID # 005059 Device Name IC Engine: East Crane

Rated Heat Input Physical Size 475.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-07-1793-4
Model 3408 DITA Serial Number G-368; SN67U11052
Location Note Upper deck
Device Description Rated bhp at 2100 rpm. Operating hours limited to 24 hr/day. 800 hr/quarter, and 2080 hr/yr. Emission controls include 4 deg. injection timing retard, turbocharged, aftercooled.

15.2 IC Engine: West Crane

Device ID # 005058 Device Name IC Engine: West Crane

Rated Heat Input Physical Size 475.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-07-1793-4
Model 3408 DITA Serial Number G-367; SN 67U11052
Location Note Upper deck
Device Description Rated bhp at 2100 rpm. Operating hours limited to 24 hr/day. 800 hr/quarter, and 2080 hr/yr. Emission controls include 4 deg. injection timing retard, turbocharged, aftercooled.

16 Maintenance Supply

Device ID # 103116 Device Name Maintenance Supply

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Location Note Platform Hidalgo
Device Description Coating/solvent brand name Chemco 211C
Application Detergent
Annual usage (gal per year) 3000
Regulatory VOC content (g/l) 836
ROC emission factor (lb/gal) 7.11
Emission controls used?No

17 Methanol Storage Tank

Device ID # 103130 Device Name Methanol Storage Tank

Rated Heat Input Physical Size
Manufacturer Custom Operator ID E-SB-02-1291-4
Model none Serial Number M-060
Location Note Mezzanine deck
Device Description Tank diameter 175 feet, not connected to vapor recovery.

18 West Wellbay Test Separator

Device ID # 103184 Device Name West Wellbay Test Separator

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1800-5
Model Serial Number V-05
Location Note Wellhead deck
Device Description Horizontal type vessel in crude oil service, diameter 4.0 feet, length 16.0 feet. Connected to gas gathering or vapor recovery.

19 Turbine Starter Engine (G-91)

Device ID # 005432 Device Name Turbine Starter Engine (G-91)

Rated Heat Input Physical Size 225.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-00-1600-4
Model 3208 Serial Number 03203327
Location Note main deck
Device Description Max Bhp rated at 2600 rpm. Operating ours limited to 24 hr/day, <200 hr/qtr and <200 hr/year. No emissions controls.

20 Fixed Roof Storage Tanks

21 Wet Oil Surge Vessel

Device ID # 103186 Device Name Wet Oil Surge Vessel

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1700-4
Model Serial Number V-08
Location Note Wellhead/mezzanine deck
Device Description Horizontal type vessel in crude oil service, diameter 10.0 feet, length 24.5 feet. Connected to gas gathering or vapor recovery.

22 Turbine Starter Engine (6-92)

Device ID # 005433 Device Name Turbine Starter Engine (6-92)

Rated Heat Input Physical Size 225.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-00-1600-4
Model 3208 Serial Number 03203335
Location Note main deck
Device Description Max rated bhp at 2600 rpm. Operating hours limited to 24 hr/day, <200 hr/qtr, and <200 hr/yr. No emissions controls.

23 Compressors

24 Well Cleanup Separator

Device ID # 103187 Device Name Well Cleanup Separator

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-09
Location Note Wellhead deck
Device Description Vertical type vessel in crude oil service, diamter 6.0 feet, length 19.5 feet. Connected to gas gathering or vapor recovery.

25 Turbine Starter Engine (6-93)

Device ID # 005434 Device Name Turbine Starter Engine (6-93)

Rated Heat Input Physical Size 225.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-00-1600-4
Model 3208 Serial Number 03203326
Location Note main deck
Device Description Max rated bhp at 2600 rpm. Operating hours limited to 24 hr/day, <200 hr/qtr, and <200 hr/yr. No emissions controls.

26 Pigging Equipment

26.1 Oil Pig Launcher

Device ID # 103175 Device Name Oil Pig Launcher

Rated Heat Input Physical Size 35.00 Cubic Feet
Manufacturer N.K.K. Operator ID E-SB-00-1900-4
Model Serial Number M-5
Location Note Sump deck
Device Description Diameter 1.33 feet, length 10.83 feet, diameter of attached pipe 1.5 feet. Connected to gas gathering or vapor recovery.

26.2 Gas Pig Launcher

Device ID # 103176 Device Name Gas Pig Launcher

Rated Heat Input Physical Size 16.00 Gallons
Manufacturer N.K.K. Operator ID E-SB-00-1900-4
Model Serial Number M-15
Location Note Sump deck
Device Description Diameter 1.0 feet, length 10.67 feet, diameter of attached pipe 0.83 feet. Connected to gas gathering or vapor recovery.

27 Vapor Recovery Stage Suction Scrubber

Device ID # 103188 Device Name Vapor Recovery Stage Suction Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-10
Location Note Wellhead deck
Device Description Vertical type vessel in crude oil service, diameter 3.0 feet, length 10.0 feet. Connected to gas gathering or vapor recovery.

28 Turbine Starter Engine (6-94)

Device ID # 005435 Device Name Turbine Starter Engine (6-94)

Rated Heat Input Physical Size 225.00 Brake Horsepower
Manufacturer Caterpillar Operator ID E-SB-00-1600-4
Model 3208 Serial Number 03203337
Location Note main deck
Device Description Max rated bhp at 2600 rpm. Operating hours limited to 24 hr/day, <200 hr/qtr, and <200 hr/yr. No emissions controls.

29 Pressure Vessels

29.1 Heavy Production Separator

Device ID # 103178 Device Name Heavy Production Separator

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1800-5
Model Serial Number V-02

Location Note Wellhead deck
Device Description Horizontal type vessel in crude oil service, diameter 7.5 feet, length 30.0 feet. Connected to gas gathering or vapor recovery.

29.2 Light Production Separator

Device ID # 103177 Device Name Light Production Separator

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1800-5
Model Serial Number V-01
Location Note Wellhead deck
Device Description Horizontal type vessel in crude oil service, diameter 7.5 feet, length 30.0 feet. Connected to gas gathering or vapor recovery.

29.3 Large Test Separator

Device ID # 103180 Device Name Large Test Separator

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1800-5
Model Serial Number V-03
Location Note Wellhead deck
Device Description Horizontal type vessel in crude oil service, diameter 6.5 feet, length 24.0 feet. Connected to gas gathering or vapor recovery.

29.4 East Wellbay Test Separator

Device ID # 103181 Device Name East Wellbay Test Separator

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1800-5
Model Serial Number V-04
Location Note Wellhead deck
Device Description Horizontal type vessel in crude oil service, diameter 4.0 feet, length 16.0 feet. Connected to gas gathering or vapor recovery.

29.5 Main Gas Compressor, 1st Stage Suction Scrubber

Device ID # 103189 Device Name Main Gas Compressor, 1st Stage Suction Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-11
Location Note Wellhead deck
Device Description Vertical type vessel in gas service, diameter 3.0 feet, length 8.0 feet. Connected to gas gathering or vapor recovery.

29.6 Main Gas Compressor, 2nd Stage Suction Scrubber

Device ID # 103190 Device Name Main Gas Compressor, 2nd Stage Suction Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-12
Location Note Wellhead deck
Device Description Vertical type vessel in gas service, diameter 4.0 feet, length 7.5 feet. Connected to gas gathering or vapor recovery.

29.7 Main Gas Compressor, 2nd Stage Suction Scrubber

Device ID # 103191 Device Name Main Gas Compressor, 2nd Stage Suction Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-13
Location Note Wellhead deck
Device Description Vertical type vessel in gas service, diameter 4.5 feet, length 10.0 feet. Connected to gas gathering or vapor recovery.

29.8 Main Gas Compressor, 3rd Stage Suction Scrubber

Device ID # 103192 Device Name Main Gas Compressor, 3rd Stage Suction Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-14
Location Note Wellhead deck
Device Description Vertical type vessel in gas service, diamter 3.0 feet, length 10.0 feet. Connected to gas gathering or vapor recovery.

29.9 Drain Pot

Device ID # 103193 Device Name Drain Pot

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-15
Location Note Wellhead deck
Device Description Vertical type vessel in drain pot service, diameter 3.0 feet, length 3.0 feet. Connected to gas gathering or vapor recovery.

29.10 Glycol Contactor

Device ID # 103194 Device Name Glycol Contactor

Rated Heat Input Physical Size
Manufacturer Alameda Tank Operator ID E-SB-00-1700-4
Model Serial Number V-16
Location Note Wellhead deck
Device Description Vertical type vessel in glycol service, diameter 3.0 feet, length 19.0 feet. Connected to gas gathering or vapor recovery.

29.11 Dry Gas Scrubber

Device ID # 103195 Device Name Dry Gas Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-17
Location Note Wellhead deck
Device Description Vertical type vessel in gas service, diameter 3.0 feet, length 7.0 feet. Connected to gas gathering or vapor recovery.

29.12 Glycol Flash Tank

Device ID # 103196 Device Name Glycol Flash Tank

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-18
Location Note Wellhead deck
Device Description Vertical type tank in glycol service, diameter 3.0 feet, length 11.0 feet. Connected to gas gathering or vapor recovery.

29.13 Glycol Regenerator

Device ID # 103197 Device Name Glycol Regenerator

Rated Heat Input Physical Size
Manufacturer Alameda Tank Operator ID E-SB-00-1600-4
Model Serial Number V-19
Location Note Mezzanine deck
Device Description Vertical column type tank in glycol service, diameter 1.0 foot, length 21.0 feet. Connected to gas gathering or vapor recovery.

29.14 Amine Contactor

Device ID # 103198 Device Name Amine Contactor

Rated Heat Input Physical Size
Manufacturer Alameda Tank Operator ID E-SB-00-1600-4
Model Serial Number V-20
Location Note Wellhead deck
Device Description Vertical column type vessel in amine service, diameter 2.0 and 3.0 feet, length 60.5 feet.
Connected to gas gathering or vapor recovery.

29.15 Amine Flash Vessel

Device ID # 103199 Device Name Amine Flash Vessel

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-21
Location Note Mezzanine deck
Device Description Vertical type vessel in amine service, diameter 4.0 feet, length 13.0 feet. Connected to gas gathering or vapor recovery.

29.16 Amine Regenerator

Device ID # 103200 Device Name Amine Regenerator

Rated Heat Input Physical Size
Manufacturer Alameda Tank Operator ID E-SB-00-1600-4
Model Serial Number V-22
Location Note Mezzanine deck
Device Description Vertical column type vessel in amine service, diameter 2.0 feet, length 42.0 feet. Connected to gas gathering or vapor recovery.

29.17 Low Pressure Flare Condensate K.O. Drum

Device ID # 103201 Device Name Low Pressure Flare Condensate K.O. Drum

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-23
Location Note Wellhead deck
Device Description Horizontal type vessel in low pressure condensate knockout drum service, diameter 5.0 feet, length 10.0 feet. Connected to gas gathering or vapor recovery.

29.18 High Pressure Flare Condensate K.O. Drum

Device ID # 103202 Device Name High Pressure Flare Condensate K.O. Drum

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-24
Location Note Wellhead deck
Device Description Horizontal type vessel in high pressure condensate knockout drum service, diameter 8.0 feet, length 20.5 feet.

Connected to gas gathering or vapor recovery????

29.19 Amine Reflux Drum

Device ID # 103203 Device Name Amine Reflux Drum

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1700-4
Model Serial Number V-25
Location Note Wellhead deck
Device Description Vertical type vessel in amine reflux service, diameter 1.46 feet, length 7.5 feet. Connected to gas gathering or vapor recovery.

29.20 Dirty Oil Storage Vessel

Device ID # 103205 Device Name Dirty Oil Storage Vessel

Rated Heat Input Physical Size
Manufacturer Wiegmann & Rose Operator ID E-SB-00-1700-4
Model Serial Number V-71
Location Note Wellhead deck
Device Description Vertical type vessel in dirty oil service, diamter 11.43 feet, length 18.5 feet. Connected to gas gathering or vapor recovery.

29.21 Dirty Oil Storage Vessel

Device ID # 103206 Device Name Dirty Oil Storage Vessel

Rated Heat Input Physical Size
Manufacturer Wiegmann & Rose Operator ID E-SB-00-1700-4
Model Serial Number V-72
Location Note Wellhead deck
Device Description Vertical type vessel in dirty oil service, diameter 11.43 feet, length 18.5 feet. Connected to gas gathering or vapor recovery.

29.22 Drain System Seal Vessel

Device ID # 103207 Device Name Drain System Seal Vessel

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1900-4
Model Serial Number V-73
Location Note Sump deck
Device Description Vertical type vessel, diameter 3.0 feet, length 6.5 feet. Connected to gas gathering or vapor recovery.

29.23 Low Temperature Separator

Device ID # 103208 Device Name Low Temperature Separator

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-86
Location Note Wellhead deck
Device Description Vertical type vessel, diameter 4.0 feet, length 15.0 feet. Connected to gas gathering or vapor recovery.

29.24 Fuel Gas Scrubber

Device ID # 103209 Device Name Fuel Gas Scrubber

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1800-5
Model Serial Number V-90
Location Note Wellhead deck
Device Description Vertical type scrubber vessel, diameter 1.5 feet, length 7.0 feet. Connected to gas gathering or vapor recovery.

30 Heat Exchangers

30.1 Glycol Regenerator Condenser

Device ID # 103225 Device Name Glycol Regenerator Condenser

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 12" x 36" AEM Serial Number E-17
Location Note Wellhead/mezzanine deck (in V 19)
Device Description Shell/tube type exchanger, heat medium glycol.

31 Speciality Units and Packages

31.1 LACT Unit

Device ID # 103125 Device Name LACT Unit

Rated Heat Input Physical Size 34290.00 BBL/Day
Manufacturer Daniel Industries Operator ID E-SB-00-1700-4
Model Serial Number M-01
Location Note Wellhead deck
Device Description Crude oil unit.

31.2 LACT Unit

Device ID # 103238 Device Name LACT Unit

Rated Heat Input Physical Size 34290.00 BBL/Day
Manufacturer Daniel Industries Operator ID E-SB-00-1700-4
Model Serial Number M-02
Location Note Wellhead deck
Device Description Crude oil unit.

31.3 LACT Unit

Device ID # 103239 Device Name LACT Unit

Rated Heat Input Physical Size 34290.00 BBL/Day
Manufacturer Daniel Industries Operator ID E-SB-00-1700-4
Model Serial Number M-03
Location Note Wellhead deck
Device Description Crude oil unit.

31.4 Meter Prover

Device ID # 103240 Device Name Meter Prover

Rated Heat Input Physical Size 34290.00 BBL/Day
Manufacturer Daniel Industries Operator ID E-SB-00-1700-4
Model Serial Number M-04
Location Note Wellhead deck
Device Description Light/mixed crude oil unit.

31.5 Cyclone Sand Separators

Device ID # 103241 Device Name Cyclone Sand Separators

Rated Heat Input Physical Size 165.00 gal/Minute
Manufacturer SWECO Operator ID E-SB-00-1700-4
Model Serial Number M-104
Location Note Mezzanine deck
Device Description In dirty oil/sand/produced water service.

31.6 Portable Pressure Blaster

Device ID # 103242 Device Name Portable Pressure Blaster

Rated Heat Input Physical Size
Manufacturer Schmidt Mfg. Co. Operator ID
Model 101-003 Serial Number
Location Note wellhead deck
Device Description In sand service, capacity 3.5 cubic feet compresed air from platform air supply.

31.7 Portable Pressure Blaster

Device ID # 103243 Device Name Portable Pressure Blaster

Rated Heat Input Physical Size
Manufacturer Abrasive Blast Equipment Operator ID
Model 2140 Serial Number 931247-02
Location Note wellhead deck
Device Description Baking soda, capacity 1.5 cubic feet compressed air from platform air supply.

32 Flares and Thermal Oxidizers

32.1 Flare Relief System

Device ID # 005423 Device Name Flare Relief System

Rated Heat Input 3800.000 MMBtu/Hour Physical Size
Manufacturer Kaldair Operator ID E-SB-00-1600-1
Model Serial Number M-12/M-13
Location Note Flare boom
Device Description HP/LP fllare type with 3800 mmBtu/hr design heat release. Flare gas HHV 1535 Btu/scf. Total sulfur content of flared gas 20,700 ppmv S as H2S max. Max expected volume gas flared 12,000 Mscf/day, 2.511 MMscf/quarter, 10.045 MMscf/year (avg.)
No emissions controls. Pilot and purge gas: flow rate 1750 scf/hr, HHV 1535 BTU/scf, sulfur content 50 ppmv S as H2S.

33 Fugitive HC Components - CLP

Device ID # 103095 Device Name Fugitive HC Components - CLP

Rated Heat Input Physical Size
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Fraction of gas/light liquid components handling H2S 80%
Fraction of oil/emulsion components handling H2S
80%
Gas/light liquid H2S concentration 12,000 ppm
Oil/emulsion H2S concentration 12,000 ppm

34 Sumps and Wastewater Tanks

34.1 Disposal Pile

Device ID # 005437 Device Name Disposal Pile

Rated Heat Input Physical Size 10.50 Square Feet Surface Area
Manufacturer N.K.K. Operator ID E-SB-00-1900-4
Model Serial Number T-75
Location Note Sump deck
Device Description Secondary vessel in produced water service; not covered, and not connected to vapor recovery.

34.2 Sump Tank

Device ID # 005438 Device Name Sump Tank

Rated Heat Input Physical Size 115.00 Square Feet Surface Area
Manufacturer N.K.K. Operator ID E-SB-00-1900-4
Model Serial Number T-72
Location Note Sump deck
Device Description Secondary vessel in drainage service, covered, not connected to vapor recovery.

34.3 Sump Deck Tank

Device ID # 005439 Device Name Sump Deck Tank

Rated Heat Input Physical Size 72.00 Square Feet Surface Area
Manufacturer N.K.K. Operator ID E-SB-00-1900-4
Model Serial Number T-74
Location Note Sump deck
Device Description Secondary vessel in drainage service, not covered, not connected to vapor recovery.

34.4 Produced Water Surge Tank

Device ID # 005436 Device Name Produced Water Surge Tank

Rated Heat Input Physical Size 36.00 Square Feet Surface Area
Manufacturer Kaiser Operator ID E-SB-00-1800-5
Model Serial Number T-31
Location Note Wellhead deck
Device Description Primary vessel in produced water service, covered, connected to vapor recovery (control efficiency 98%).

34.5 Cuttings Dewater Shaker (Drilling)

Device ID # 005440 Device Name Cuttings Dewater Shaker (Drilling)

Rated Heat Input Physical Size 46.00 Square Feet Surface Area
Manufacturer SWECO Operator ID E-SB-00-1700-4
Model Serial Number M-104
Location Note Mezzanine deck
Device Description Primary vessel in waste water service, not covered, not connected to vapor recovery.

34.6 Oil/Water CPI Separator

Device ID # 005444 Device Name Oil/Water CPI Separator

Rated Heat Input Physical Size 50.00 Square Feet Surface Area
Manufacturer Pace Setter Operator ID E-SB -00-1700-4
Model Serial Number M-70
Location Note Mezzanine deck
Device Description Secondary vessel in drainage/waste water service, covered, not connected to vapor recovery.

35 Oil Water Separators

35.1 CPI Separator

Device ID # 005442 Device Name CPI Separator

Rated Heat Input Physical Size 375.00 gal/Minute
Manufacturer Pace Setter Operator ID E-SB-00-1800-5
Model Serial Number M-32
Location Note Wellhead deck
Device Description Covered and connected to vapor recovery (control efficiency 95%).

Throughput: 0.54 mmgal/day; 49.3 mmgal/qtr, 197.1 mmgal/yr.

35.2 CPI Separator

Device ID # 005443 Device Name CPI Separator

Rated Heat Input Physical Size 375.00 gal/Minute
Manufacturer Pace Setter Operator ID E-SB-00-1800-5
Model Serial Number M-33
Location Note Wellhead deck
Device Description Covered and connected to vapor recovery (control efficiency 95%).

Throughput 0.54 mmgal/day; 49.3 mmgal/qtr; 197.1 mmgal/yr.

36 Supply Boats

36.1 Supply Boat (basis: M/V Victory Seahorse)

Device ID # 103110 Device Name Supply Boat (basis: M/V Victory Seahorse)

Rated Heat Input Physical Size
Manufacturer Operator ID
Model Serial Number
Location Note OCS
Device Description

36.1.1 Main Engines

Device ID # 005426 Device Name Main Engines

Rated Heat Input Physical Size 5000.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Two main engines at 2500 bhp each.

36.1.2 Generator Engines

Device ID # 103117 Device Name Generator Engines

Rated Heat Input Physical Size 600.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Two generator engines at 300 bhp each, uncontrolled for NOx.

36.1.3 Bow Thruster Engine

Device ID # 105053 Device Name Bow Thruster Engine

Rated Heat Input Physical Size 515.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description One bow thruster engine at 515 bhp, uncontrolled for NOx.

36.2 Supply Boat (basis: M/V San Miguel / M/V Santa Cruz)

Device ID # 103118 Device Name Supply Boat (basis: M/V San Miguel / M/V Santa Cruz)

Rated Heat Input Physical Size
Manufacturer Operator ID
Model Serial Number
Location Note OCS
Device Description

36.2.1 Main Engines

Device ID # 103119 Device Name Main Engines

Rated Heat Input Physical Size 4000.00 Brake Horsepower
Manufacturer Caterpillar Operator ID
Model 3516B Serial Number
Location Note
Device Description Two low NOx main engines (2000 bhp each) total 4000 bhp.

36.2.2 Generator Engines

Device ID # 103120 Device Name Generator Engines

Rated Heat Input Physical Size 600.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Two gensets at 300 bhp each for 600 bhp total, uncontrolled for NOx.

36.2.3 Bow Thruster Engine

Device ID # 105091 Device Name Bow Thruster Engine

Rated Heat Input Physical Size 515.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description One bow thruster at 515 bhp, uncontrolled for NOx.

36.3 Spot Charter Boat Engines

Device ID # 105093 Device Name Spot Charter Boat Engines

Rated Heat Input Physical Size 5000.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description

36.4 Emergency Response Boat Engines (basis: Clean Seas III)

Device ID # 105094 Device Name Emergency Response Boat Engines (basis: Clean Seas III)

Rated Heat Input Physical Size 4400.00 Brake Horsepower
Manufacturer Operator ID
Model Serial Number
Location Note
Device Description Total engine horsepower 4400 bhp, uncontrolled for NOx.

37 Crew Boats

37.1 Crew Boat (basis: M/V Price Tide)

Device ID # 103109 Device Name Crew Boat (basis: M/V Price Tide)

Rated Heat Input Physical Size
Manufacturer Detroit Diesel Operator ID
Model 12V71TI Serial Number
Location Note Pacific OCS
Device Description

38 Maintenance Activities

39 Production Drain Receiver

Device ID # 103204 Device Name Production Drain Receiver

Rated Heat Input Physical Size
Manufacturer General Welding Operator ID E-SB-00-1900-4
Model Serial Number V-70

Location Note Wellhead deck
Device Description Horizontal type vessel, diameter 5.0 feet, length 15.5 feet. Connected to gas gathering or vapor recovery.

40 Well Utility Pump

Device ID # 103173 Device Name Well Utility Pump

Rated Heat Input Physical Size 20.00 Horsepower (Electric Motor)
Manufacturer Operator ID E-SB-01-1191-4
Model Serial Number P-104
Location Note Wellhead deck
Device Description Pumps diesel fuel, powered by 20 hp electric motor.

B EXEMPT EQUIPMENT

1 Production Preheater

Device ID # 103107 Device Name Production Preheater

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 28" x 252" AJU Serial Number E-1
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger in light production service, heat medium Caloria.

2 Maintenance Supply

Device ID # 103112 Device Name Maintenance Supply

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Part 70 Insig? No APCD Rule Exemption:
Location Note Platform Hidalgo
Device Description Coating/solvent brand name Carboline 858
Application Primer
Annual usage (gal per year) 260
Regulatory VOC content (g/l) 350
ROC emission factor (lb/gal) 2.85

Emission controls used?Yes
Emission controls description Overspray tarps

3 Maintenance Supply

Device ID # 103113 Device Name Maintenance Supply

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Part 70 Insig? No APCD Rule Exemption:
Location Note Platform Hidalgo
Device Description Coating/solvent brand name Carbomastic 15
Application Coating
Annual usage (gal per year) 500
Regulatory VOC content (g/l) 340
ROC emission factor (lb/gal) 2.06
Emission controls used?Yes
Emission controls description Overspray tarps

4 Production Preheater

Device ID # 103210 Device Name Production Preheater

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 28" x 252" AJU Serial Number E-2
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger in heavy production, heat medium Caloria.

5 Maintenance Supply

Device ID # 103114 Device Name Maintenance Supply

Rated Heat Input Physical Size
Manufacturer Operator ID 300
Model Serial Number
Part 70 Insig? No APCD Rule Exemption:
Location Note Platform Hidalgo
Device Description Coating/solvent brand name Carbothane 134 HS
Application Coating
Annual usage (gal per year) 500

Regulatory VOC content (g/l) 340
ROC emission factor (lb/gal) 2.86
Emission controls used? Yes
Emission controls description Overspray tarps

6 Large Test Preheater

Device ID # 103211 Device Name Large Test Preheater

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 24" x 204" AJU Serial Number E-3
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type in production service, heat medium Caloria.

7 West Wellbay Test Preheater

Device ID # 103213 Device Name West Wellbay Test Preheater

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 15" x 108" AJU Serial Number E-5
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger in production fluids service, heat medium Caloria.

8 Shipping Pump Recycle Cooler

Device ID # 103214 Device Name Shipping Pump Recycle Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-03-1391-3
Model 17" x 72" AEU Serial Number E-6
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger in recirculation cooler service, heat medium sea water.

9 Wet Oil Surge Vessel Startup Heater

Device ID # 103215 Device Name Wet Oil Surge Vessel Startup Heater

Rated Heat Input Physical Size
Manufacturer NATCO Operator ID E-SB-00-1700-4
Model Serial Number E-8
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck (inside V-08)
Device Description Coil type exchanger, startup heater for wet oil surge vessel (V-8), heat medium jet water.

10 MGC Vapor Recovery Discharge Cooler

Device ID # 103216 Device Name MGC Vapor Recovery Discharge Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-03-1391-3
Model 19" x 204" AEU Serial Number E-10
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger in vapor recovery discharge cooler service, heat medium sea water.

11 Main Gas Compressor 1st Stage Discharge Cooler

Device ID # 103217 Device Name Main Gas Compressor 1st Stage Discharge Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-03-1391-3
Model 26" x 192" AEU Serial Number E-11
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium sea water.

12 Main Gas Compressor 2nd Stage Discharge Cooler

Device ID # 103218 Device Name Main Gas Compressor 2nd Stage Discharge Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-03-1391-3
Model 25" x 198" AEU Serial Number E-12
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium sea water.

13 Main Gas Compressor 3rd Stage Discharge Cooler

Device ID # 103219 Device Name Main Gas Compressor 3rd Stage Discharge Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 22" x 180" AEU Serial Number E-13
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium sea water.

14 Lean/Rich Glycol Exchanger

Device ID # 103221 Device Name Lean/Rich Glycol Exchanger

Rated Heat Input Physical Size
Manufacturer BASTEX Operator ID E-SB-03-1391-3
Model 3" x 1½" x 144" Type II Serial Number E-15A
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium glycol.

15 Lean/Rich Glycol Exchanger

Device ID # 103222 Device Name Lean/Rich Glycol Exchanger

Rated Heat Input Physical Size
Manufacturer BASTEX Operator ID E-SB-03-1391-3
Model 3" x 1½" x 144" Type II Serial Number E-15B
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium glycol.

16 Lean/Rich Glycol Exchanger

Device ID # 103223 Device Name Lean/Rich Glycol Exchanger

Rated Heat Input Physical Size
Manufacturer BASTEX Operator ID E-SB-03-1391-3
Model 3" x 1½" x 144" Type II Serial Number E-15C
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium glycol.

17 Lean Amine Cooler

Device ID # 103226 Device Name Lean Amine Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 19" x 102" AEM Serial Number E-18
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium sea water.

18 Lean/Rich Amine Exchanger

Device ID # 103231 Device Name Lean/Rich Amine Exchanger

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 21" x 96" AFU Serial Number E-21A
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck

Device Description Shell/tube type exchanger, heat medium DEA.

19 Lean/Rich Amine Exchanger

Device ID # 103232 Device Name Lean/Rich Amine Exchanger

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 21" x 96" AFU Serial Number E-21B
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium DEA.

20 Lean Glycol Cooler

Device ID # 103233 Device Name Lean Glycol Cooler

Rated Heat Input Physical Size
Manufacturer R.W. Holland Operator ID E-SB-03-1391-3
Model Horizontal Serial Number E-22
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium glycol.

21 MGC Vapor Recovery Stage Suction Cooler

Device ID # 103234 Device Name MGC Vapor Recovery Stage Suction Cooler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 21" x 168" AJU Serial Number E-23
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium sea water.

22 Internal Heater, Dirty Oil Storage Vessel

Device ID # 103235 Device Name Internal Heater, Dirty Oil Storage Vessel

Rated Heat Input Physical Size
Manufacturer Wiegmann & Rose Operator ID E-SB-11-5323-8
Model 22" x 47" Serial Number

Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Plate coils type exchanger in dirty oil heater service.

23 Internal Heater, Dirty Oil Storage Vessel

Device ID # 103236 Device Name Internal Heater, Dirty Oil Storage Vessel

Rated Heat Input Physical Size
Manufacturer Wiegmann & Rose Operator ID E-SB-11-5323-8
Model 22" x 47" Serial Number E-72
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Plate coils type exchager in dirty oil heater service.

24 Rescue Boat

Device ID # 103124 Device Name Rescue Boat

Rated Heat Input Physical Size 9.50 Brake Horsepower
Manufacturer H.E.R.B. Operator ID E-SB-07-1793-4
Model Serial Number M-125
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck
Device Description Rated at 9.5 BHP (max), fuel higher heating value 21070. Operating hours limited to 24 hr/day, <200 hours/qtr, and <200 hrs/year. No emissions controls.

25 IC Engine: Emergency Standby Generator

Device ID # 005060 Device Name IC Engine: Emergency Standby Generator

Rated Heat Input Physical Size 1250.00 Brake Horsepower
Manufacturer Detroit Diesel Operator ID G-90
Model G-90; SN 16V149TA Serial Number 16E00008165
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck
Device Description Operating hours limited to 24 hr/day, <200 hr/qtr and <200 hr/year. No emissions controls.

26 IC Engine: Standby Fire Water Pump

Device ID # 005063 Device Name IC Engine: Standby Fire Water Pump

Rated Heat Input Physical Size 517.00 Brake Horsepower
Manufacturer Detroit Diesel Operator ID E-SB-00-1800-5
Model 12V71 Serial Number P-50; SN 12VA078659
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Operating hours limited to 24 hr/day, <200 hr/qtr and <200 hr/year. No emissions controls.

27 Compressor Lube Oil Tank

Device ID # 103126 Device Name Compressor Lube Oil Tank

Rated Heat Input Physical Size 70.00 Gallons
Manufacturer Bluewater M.I. Operator ID E-SB-05-1591-5
Model Serial Number T-10
Part 70 Insig? No APCD Rule Exemption:
Location Note Main deck
Device Description Not connected to vapor recovery.

28 Diesel Storage Tank, Fire Water Pump

Device ID # 103127 Device Name Diesel Storage Tank, Fire Water Pump

Rated Heat Input Physical Size 70.00 Gallons
Manufacturer Byron-Jackson Operator ID E-SB-05-1591-5
Model Serial Number T-53
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Horizontal type tank, not connected to vapor recovery.

29 Diesel Storage Tank, East Crane

Device ID # 103128 Device Name Diesel Storage Tank, East Crane

Rated Heat Input Physical Size 13230.00 Gallons
Manufacturer Operator ID E-SB-00-1900-04
Model Serial Number T-90
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck (northeast cap truss)
Device Description Horizontal type flat roof tank, diameter 5.0 feet
Not connected to vapor recovery.

30 Diesel Storage Tank, West Crane

Device ID # 103129 Device Name Diesel Storage Tank, West Crane

Rated Heat Input Physical Size 26796.00 Gallons
Manufacturer Operator ID E-SB-00-1900-04
Model Serial Number T-91
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck (west cap truss)
Device Description Horizontal type flat roof tank, diameter 5.0 feet
Not connected to vapor recovery.

31 Compressor Lube Oil Tank

Device ID # 103131 Device Name Compressor Lube Oil Tank

Rated Heat Input Physical Size 70.00 Gallons
Manufacturer Bluewater M.I. Operator ID E-SB-05-1591-5
Model Serial Number T-11
Part 70 Insig? No APCD Rule Exemption:
Location Note main deck
Device Description Not connected to vapor recovery.

32 Disposal Pile Pump

Device ID # 103106 Device Name Disposal Pile Pump

Rated Heat Input Physical Size
Manufacturer Flygt Operator ID E-SB-00-1900-4
Model DS3080P Serial Number P-75

Part 70 Insig? No APCD Rule Exemption:
Location Note Sump deck
Device Description Pile pump pumps wet oil, rated capacity 13 gpm, powered pneumatic pump at 35 psi.

33 East Wellbay Test Preheater

Device ID # 103212 Device Name East Wellbay Test Preheater

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-00-1700-4
Model 15" x 204" AJU Serial Number E-4
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger in production service, heat medium Caloria.

34 Dry Gas/Lean Glycol Exchanger

Device ID # 103220 Device Name Dry Gas/Lean Glycol Exchanger

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co. Operator ID E-SB-03-1391-3
Model 11" x 168" AEU Serial Number E-14
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger, heat medium glycol.

35 Glycol Regenerator Reboiler

Device ID # 103224 Device Name Glycol Regenerator Reboiler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 18" x 142" AKU Serial Number E-16
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium glycol.

36 Amine Regenerator Reboiler

Device ID # 103227 Device Name Amine Regenerator Reboiler

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-03-1391-3
Model 36"/69 x 102" AKU Serial Number E-19
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube type exchanger, heat medium DEA.

37 Amine Regenerator Condenser

Device ID # 103229 Device Name Amine Regenerator Condenser

Rated Heat Input Physical Size
Manufacturer Energy Exchange Co Operator ID E-SB-00-1700-4
Model 23" x 96" AEU Serial Number E-20
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead/mezzanine deck
Device Description Shell/tube exchanger, heat medium DEA.

38 Fuel Gas Preheater

Device ID # 103237 Device Name Fuel Gas Preheater

Rated Heat Input Physical Size
Manufacturer Operator ID E-SB-00-10519-3
Model Serial Number E-90
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Shell/tube type exchanger in fuel gas service, heat medium fuel gas.

39 Marine Survival Craft

Device ID # 103121 Device Name Marine Survival Craft

Rated Heat Input Physical Size 36.00 Brake Horsepower
Manufacturer Whittaker Operator ID E-SB-06-1691-3
Model CA5400-0K001 Serial Number M-120
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck
Device Description Operating hours limited to less than 200 hours per quarter and per year.

40 Marine Survival Craft

Device ID # 103122 Device Name Marine Survival Craft

Rated Heat Input Physical Size 36.00 Brake Horsepower
Manufacturer Whittaker Operator ID E-SB-07-1791-4
Model CA5400-0K001 Serial Number M-121
Part 70 Insig? No APCD Rule Exemption:
Location Note Upper deck
Device Description Operating hours limited to less than 200 hours pwer quarter and per year.

41 Marine Survival Craft

Device ID # 103123 Device Name Marine Survival Craft

Rated Heat Input Physical Size 36.00 Brake Horsepower
Manufacturer Whittaker Operator ID E-SB-00-1800-5
Model CA5400-0K001 Serial Number M-122
Part 70 Insig? No APCD Rule Exemption:
Location Note Wellhead deck
Device Description Operating hours limited to less than 200 hours pwer quarter and per year.

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