Santa Barbara County
Air Pollution Control District
Our Vision: Clean Air

PROPOSED

PERMIT to OPERATE No. 9101
and
PART 70 OPERATING PERMIT No. 9101

EXXON – SYU PROJECT
PLATFORM HARMONY

PARCEL OCS P-0190
SANTA YNEZ UNIT
SANTA BARBARA COUNTY, CALIFORNIA
OUTER CONTINENTAL SHELF

OPERATOR

Exxon Company, U.S.A. ("Exxon")

OWNERSHIP

Exxon Company, U.S.A. ("Exxon")

Santa Barbara County
Air Pollution Control District

October 19, 1999

Santa Barbara County
Air Pollution Control District
Our Vision: Clean Air

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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-leakpath
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
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
LFC	Las Flores Canyon
LHV	lower heating value
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
POPCO	Pacific Offshore Pipeline Company
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 μm 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 District or District or APCD
scf	standard cubic feet
scfd	standard cubic feet per day
scfm	standard cubic feet per minute
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison
SO_x	sulfur oxides
SYU	Santa Ynez Unit
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

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1.0 Introduction

1.1 Purpose

General. The Santa Barbara County Air Pollution Control District (APCD) is responsible for implementing all applicable federal, state and local air pollution requirements which affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 55, 60, 61, 63, 68, 70 and 82. The State regulations may be found in the California Health & Safety Code, Division 26, Section 39000 et seq. The applicable local regulations can be found in the APCD's Rules and Regulations.

The County is designated as an ozone nonattainment area for both the state and federal ambient air quality standards. The County is also designated a nonattainment area for the state PM_{10} ambient air quality standard.

Part 70 Permitting. The issuance of this Part 70 permit to Platform Harmony satisfies the permit issuance requirements of the APCD's Part 70 operating permit program. Platform Harmony is a part of the *Exxon - Santa Ynez Unit ("SYU") Project* stationary source (SSID = 1482), which is a major source for VOC[1], NO_x, CO, SO_x and PM_{10}. 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. Conditions listed in Section 9.D are "APCD-only" enforceable.

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

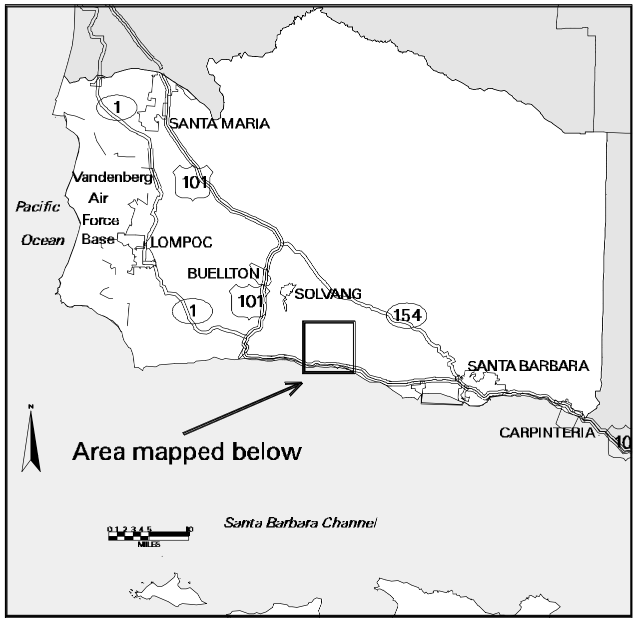
1.2 Facility Overview

1.2.1 Facility Overview: Exxon U.S.A Corporation ("Exxon") is the sole owner and operator of Platform Harmony, located in the Santa Ynez Unit on lease tract OCS P-0190 approximately 25 miles west of the City of Santa Barbara (Lambert Zone coordinates x = 817981 feet, y = 826368 feet). The platform is situated in the Southern Zone of Santa Barbara County. Figure 1.1 shows the relative location of Platform Harmony off of the Santa Barbara County coast. The platform is operated by Exxon and has the following percentage of working interest ownership: Exxon 100 percent.

[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 Harmony

Santa Ynez Unit Project - (onshore)



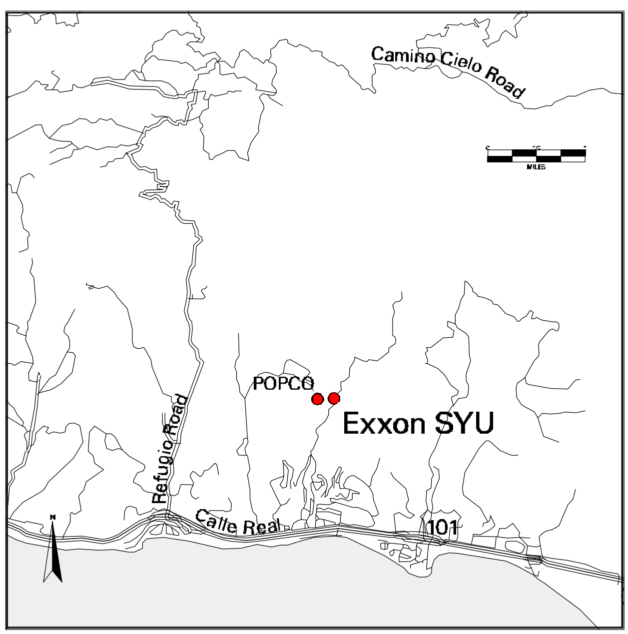
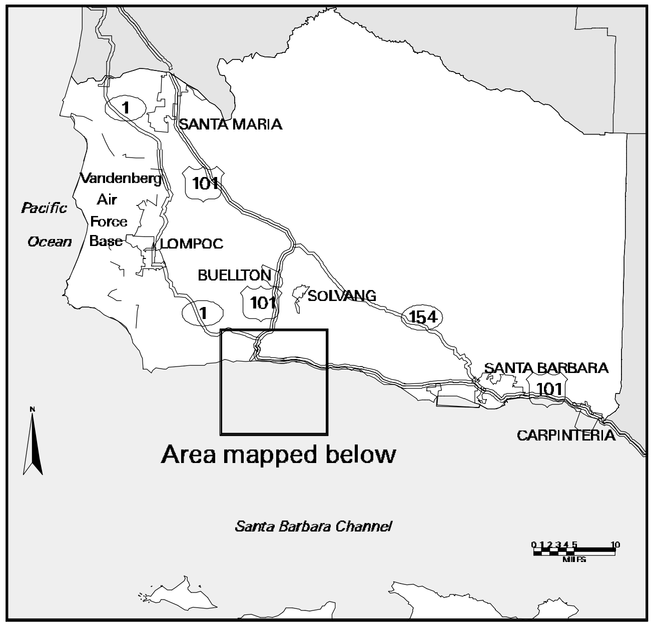
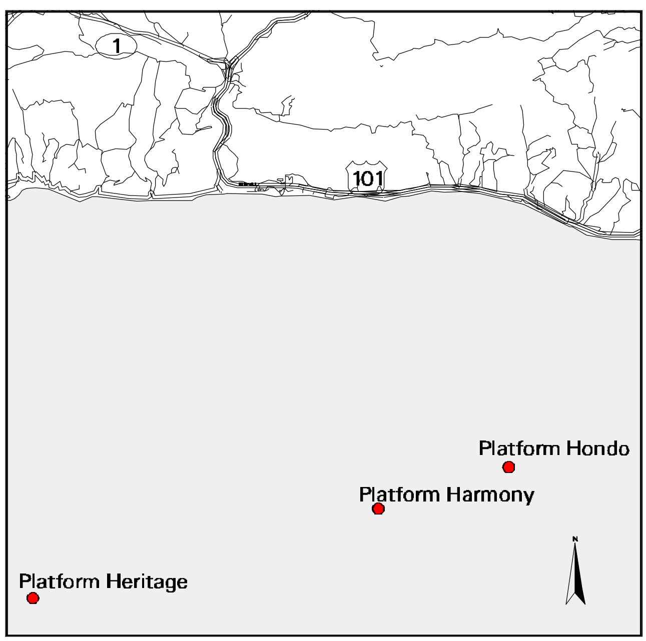


Figure 1.1 - Location Map for Platform Harmony (continued)

Exxon Santa Ynez Unit Project - (offshore)





Platform Harmony is an eight leg, 60 well slot platform that was installed in a water depth of 1200 feet during the 1989 to 1992 time frame. Drilling operations began in 1993. Platform Harmony produces sour natural gas and crude oil. The average gravity of the produced crude oil is 18-19 °API. Emulsion and produced gas from Platform Harmony is shipped via subsea pipelines to Exxon's onshore processing facilities in Las Flores Canyon (LFC) approximately 20 miles north of Santa Barbara. Primary separation of the oil emulsion from the produced gas takes place on Platform Harmony. The oil emulsion is shipped via a 20-inch pipeline to the LFC facility. The produced gas from Platform Harmony is compressed on the platform and a portion is shipped via a 12-inch pipeline to Platform Hondo and then to the POPCO gas plant at LFC for sale and/or transport. The design production rate for Platform Harmony is 75 thousand barrels of emulsion per day and 75 million standard cubic feet of produced gas per day. Primary power for the platform is supplied by an onshore 49 megawatt cogeneration power plant at LFC.

The *Exxon - SYU Project* stationary source consists of the following 5 facilities:

- Platform Harmony (FID= 8018)
- Platform Heritage (FID= 8019)
- Platform Hondo (FID= 8009)
- Las Flores Canyon Oil and Gas Plant (FID= 1482)
- POPCO Gas Plant (FID= 3170)

1.2.2 Facility New Source Review Overview: Since the issuance of the initial operating permit on September 4, 1994, there have been seven permits. These were:

PTO Mod 9101-01: Dedication of 20.68 tpy of SO_x ERCs to comply with Rule 359 requirements. This permit was issued on 1/25/95.

PTO Mod 9101-02: This permit added condition No. 34 (*Crew and Supply Boat Stationary Source Maximum Permitted Emissions and Operational Limits*). The purpose was to redefine the stationary source's annual potential to emit, which is used to determine fees for Air Quality Plans pursuant to Rule 210. This permit was issued on 5/2/96.

Trn O/O 9101-01: Exxon's application for transfer of ownership of Chevron's portion of two reservoir leases from which Harmony draws oil, to Exxon. Exxon stated that Chevron had only non-consent ownership. This permit was issued on 5/2/96.

ATC 9640, PTO 9640: These permits approved the installation and operation of a shipping gas compressor (CZZ-306). BACT and offsets were required. ROC emissions increased by 0.56 tpy. The ATC was issued on 12/18/96 and the PTO was issued on 11/12/97.

ATC 9827: This permit authorized the installation of a new sales gas pipeline between Platforms Harmony and Heritage. BACT and offsets were required. ROC emissions increased by 0.29 tpy. This permit was issued on 1/21/98.

ATC/PTO 10037: This permit authorized changes included the revision of project emission factors, reduction of permitted solvent emissions, updated fugitive hydrocarbon leak path inventory, revised the stationary source crew and supply boat potential to emit downward and modified the allowable number of pigging operations. NO_x, ROC, CO, SO_x, PM and PM_{10} emissions decreased by 169 tpy, 60 tpy, 43 tpy, 38 tpy and 14 tpy respectively. This permit was issued on 1/7/99.

ATC/PTO 10170: This permit authorized the use of larger crew and supply boats. Only short-term hourly and daily emissions increased. Through limitations of allowable fuel use, long term quarterly and annual emissions did not increase.

1.3 Emission Sources

Air pollution emissions from Platform Harmony are the result of 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, the Platform as a whole, and also lists the potential emissions from non-permitted emission units.

The emission sources include the following:

- Crew, supply and emergency response boat engines
- Piping components (such as valves and flanges)
- Flare
- Helicopters
- Solvent cleaning
- Process heater
- IC engines

A list of all permitted equipment is provided in Section 10.4.

1.4 Emission Control Overview

Air quality emission controls are utilized on Platform Harmony for a number of emission units to reduce air pollution. Additionally, the use of onshore generated electricity from the 49 MW Cogeneration Power Plant at Las Flares Canyon allows Platform Harmony to operate without large gas turbine-powered generators or compressors. The emission controls employed on the platform include:

- An Inspection and Maintenance program for detecting and repairing leaks of hydrocarbons from piping components, consistent with the requirements of Rule 331, to reduce hydrocarbon 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 or less.

- Installing an electric motor drive on one of the two crane engines.

- An amine unit on the platform removes sulfur from the fuel gas used on the platform thereby reducing SO_x emissions.

1.5 Offsets/Emission Reduction Credit Overview

Offsets: Modifications permitted under ATC permits 9640 and 9827 required ROC offsets. Emission Reduction Credits ("ERCs") in the amount of 0.67 tpy were secured for PTO 9640's offset liability of 0.56 tpy through PTO 9651 by the implementation of an enhanced I&M program at Las Flores Canyon. ERCs in the amount of 0.35 tpy were secured for ATC 9827's offset liability of 0.29 tpy through ERC Certificate No. 0004-0103 by the implementation of an enhanced I&M program at Las Flores Canyon. The ROC offset requirements are detailed in Table 7.1.

Under PTO 9101-01, Exxon secured 20.68 tpy of SO_x ERCs for Platform Harmony. These ERCs were created due to the shutdown of the OS&T vessel. The ERCs are required pursuant to Rule 359, from which Exxon obtained an exemption from the planned flaring sulfur content standard of 239 ppmv.

Emission Reduction Credits: Platform Harmony does not provide ERCs to any project or ERC Certificate.

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: Equipment or activities exempted from permitting under APCD Rule 202 are considered as insignificant emissions units. The guidance under the USEPA's White Paper II, Sections C.2.c and C.2.d, applies to insignificant emission units. (*See Attachment 10.4 for the Insignificant Emission Unit list)*

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. Exxon has made a request for a permit shield. Table 1.1 summarizes the permit shield granted to Exxon.

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. Exxon made no request for permitted alternative operating scenarios.

Exxon lists their main operating scenario as: "Platform Harmony is an oil and gas production platform (SIC 1311). Its main products are crude emulsion and gas. The platform also produces byproducts from crude oil and gas production operations. Normal facility operations include periods of startup, shutdown and turnaround. Periodically, malfunctions may occur."

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 is expected to 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 their mailing address is:

Mr. Jeffrey J. Woodbury
Production Manager
Exxon Company, U.S.A. (a division of Exxon Corporation)
Post Office Box 61707
1555 Poydras Street
New Orleans, LA 70161-1707

Telephone: (504) 561-4222

TABLE 1.1 – PERMIT SHIELD FOR EXXON PLATFORM HARMONY

APPLICABLE RULE/REGULATION	AFFECTED EMISSION UNIT(S)	JUSTIFICATION FOR GRANTING PERMIT SHIELD
APCD Rule 326	none	Exxon does not operate equipment that is subject to this rule.
APCD Rule 333	Crew and Supply Boats (EQ No. 6-x, 7-x, 8-1)	Per the Clean Air Act, the APCD is prohibited from directly regulating the emissions from mobile sources. Section 328 of the CAAA therefore did not provide authority to regulate the emissions from engines being used for the propulsion of vessels. As such, Rule 333 emission standards do not apply to the propulsion engines.
40 CFR 60 NSPS	All	None of the equipment on the Platform are currently subject to a New Source Performance Standard.

2.0 Process Description

2.1 Process Summary

Platform Harmony produces sour (with H_2S) crude oil (oil/water emulsion) and gas. The design rate for the platform is 75 kbpd of oil emulsion and 75 mmscfd of produced gas containing up to 30,000 ppmv H_2S. The platform production equipment includes wells, pressure vessels, shipping pumps, transfer pumps, gas and refrigerant compressors, tanks, a glycol contactor and regenerator, a depropanizer, an amine contactor and still, a process heater, sumps, heat exchangers and coolers, and pipeline pigging equipment. No separation of the produced oil and water emulsion takes place onboard the platform. All produced liquids are shipped to Exxon's Las Flores Canyon facility for dehydration via a 20-inch sub sea pipeline. Produced gas containing H_2S is separated from the produced liquids in the platform's gas/liquid separators and scrubbers. The gas on the platform is then compressed, dehydrated and refrigerated to remove heavy ends. The resulting gas can be shipped to the POPCO gas processing plant in Las Flores Canyon for sale and/or transport via a 12-inch sub sea pipeline to Hondo, combusted as fuel following sweetening, or compressed for re-injection or gas lift gas. The current daily production rate is approximately 27 kbpd of emulsion at less than 12 kbpd of water and 39 mmscfd of produced gas.

2.1.1 *Production*: The platform has 60 well slots. There are presently 29 well completions onboard the platform. Of the 29 completions, 24 are producing oil and gas and four are used as gas cap gas injection wells and one is used as a disposal well. At this time, 15 wells are flowing wells and 9 are produced by means of gas lift recovery.

The well bay contains four production manifolds and one gas injection manifold. Each production manifold contains the following headers:

- Monterey Production Header which sends the produced emulsion and gas from the wells to one of two Monterey Production Separators.

- Monterey Test Header which sends the produced emulsion and gas from a well to one of two Monterey Test Separators.

- High Pressure Production Header which was installed to connect to a potential future High Pressure Production Separator.

- High Pressure Test Header which was installed to connect to a potential future High Pressure Test Separator.

- Gas Lift Header which supplies each well with dehydrated and conditioned produced gas for gas lift.

- Chemical Batch Treatment Header which is used to periodically inject batch chemicals downhole.

- Well Cleanup Header which sends the produced emulsion and gas following an initial completion or a well workover to the Well Cleanup Separator.

The gas injection manifold is connected to up to three wells and supplies dehydrated and conditioned produced gas to the well for re-injection or back into the formation.

2.1.2 *Gas/Emulsion Separation*: All separators located on the platform are two phase (i.e., gas and liquid). Capacities of separators are as follows:

- Monterey Production Separators (MBD-101 and 102): 50 kbpd emulsion; 40 mmscfd gas.
- Monterey Test Separators (MBD-103 and 104): 7.5 kbpd emulsion; 7.5 mmscfd gas.
- Well Cleanup Separator (MBD-113): 5 kbpd emulsion, 5 mmscfd gas.

All emulsion is routed to the Emulsion Surge Tank (MBJ-110). Sour gas is routed to the First Stage Suction Scrubber (MBF-114) where it is then compressed, dehydrated and conditioned for use as gas sales and/or transport gas to POPCO, or compressed for gas injection or gas lift. A side stream of conditioned sour gas is routed to the fuel gas treating unit where the gas is contacted with an amine solution to remove hydrogen sulfide. This sweet gas is then scrubbed and filtered prior to entering the platform fuel gas header.

There are four types of drain systems on the platform: Closed Drain, Deck/Open Drain, Glycol Drain and Amine Drain. The Closed Drain system collects hydrocarbon contaminated drainage from all of the process vessels, equipment and manifolds as well as selected skid and deck drains that have a high potential to contain hydrocarbons and/or chemicals. The liquids collect in the Closed Drain Sump (MBH-132) from where it is transferred by one of two pumps (PBH 363 or 364) to the Emulsion Surge Tank.

In general, the Deck/Open Drain System collects all production deck and cellar deck surface drainage as well as liquids from non-hydrocarbon atmospheric drains. All of the decks have kick plates which are seal welded around deck penetrations and the perimeter to prevent any fluids from spilling over. Any liquid spilled on the deck will collect in the deck drains and will then flow to the Open Drain Sump (ABH-406). Any hydrocarbons that may be present, however, are skimmed from the Open Drain sump and pumped to the Closed Drain System for eventual disposal in the oil production system while water from the Open Drain Sump gravity flows to the Skim Pile for release to the ocean. The drilling deck drains are handled by a separate drain system tied to the Drill Deck Drain Settling Tank (ABJ-417) to prevent contamination of the oil production system. The solids settling tank separates the solids (drilling additives/solids and mud) from the liquids for disposal to the disposal caisson. The separated liquids gravity flow to both the Open Drain Sump and the Skim Pile. The wellbay area has a separate sump (ABH-405) to collect surface drainage from the wellbay area. This drainage is pumped to the Drill Deck Drain Settling Tank.

The Glycol Drain System is a closed system which collects drainage from the Glycol Regeneration System equipment, the glycol contactor, and the Depropanizer Reboiler. The glycol drainage flows from a collection header to a sump from which it is pumped, filtered and returned to the Glycol

Regeneration System. The Glycol Drain Sump is also used as a means for adding glycol makeup from tote tanks to the system.

The Amine Drain System is a closed system which collects drainage from the Amine Regeneration equipment and the Fuel Gas Scrubber (MBF-120). The amine drainage flows through a collection header to a sump from which it is pumped, filtered, and returned to the Amine Regeneration System. The Amine Sump is also used as means for adding amine make-up from tote tanks to the system.

2.1.3 *Waste Water Treatment*: There are no waste water treatment facilities that remove produced water from the oil on this platform.

2.1.4 *Well Testing and Maintenance*: In order to measure individual well production rates, production is directed to one of two test separators. The production test facilities allow for remote testing of any well. Liquids exiting the test separators flow to the Emulsion Surge Tank while sour gas is routed to the First Stage Suction Scrubber.

After a well workover is completed, the oil production from the well is started by producing the well to either a test separator or the Well Cleanup Separator (MBD-113). This segregates the well from the rest of the producing wells. Producing the well into a test separator prevents upsetting the normal production on the platform should the new well have unanticipated flow surges. Producing the well into the Well Cleanup Separator allows the lowering of the tubing pressure to a level which will facilitate flow. Additionally, it will prevent the separators from being contaminated with material left in the well from the workover. This tank is equipped with a washout jet header system and ram type drain valves to assist in solids removal. Following treatment in the Well Cleanup Separator, emulsion is routed to the Emulsion Surge Tank and gas to the First Stage Suction Scrubber.

2.1.5 *Emulsion Breaking and Crude Oil Storage*: Produced fluids are in the form of a tight oil/water emulsion which can be broken through the use of chemicals. Demulsifying chemicals can be injected both downhole and in the surface facilities, if required.

The Emulsion Surge Tank collect liquids from the two Monterey Test Separators, the two Monterey Production Separators, the STV Compression Suction Scrubber, the First Stage Suction Scrubber, the Well Cleanup Separator, the Amine Reflux Accumulator, the Glycol Hydrocarbon Separator and the Closed Drain Sump.

2.1.6 *Crude Oil Shipping*: Liquids are shipped from the Emulsion Surge Tank to Las Flores Canyon via a 20" sub sea pipeline using one or more of the positive displacement screw type Emulsion Shipping Pumps (PAX-331, 332, 333) operated simultaneously to provide the desired flow capacity.

The pumps take suction from the Emulsion Surge Tank and pump the emulsion to pipeline discharge pressure which may vary from a few hundred psi to over 1000 psi, depending on throughput and emulsion properties. The liquid from the pumps is combined with recovered heavy ends from the conditioning unit (depropanizer) prior to being metered and sampled in the emulsion shipping

ACT unit (ZAU-518) for production allocation and leak detection. This stream then combines with the emulsion from Hondo and Heritage and enters the emulsion pipeline that contains a pig launcher on the platform. When a pig is being launched, the flow is directed through the emulsion pig launcher (KAH-791).

2.1.7 *Gas Compression, Dehydration and Conditioning*: The produced gas system is designed to collect and compress virtually all produced hydrocarbon vapors, dehydrate the compressed gas to a dew point of -40°F, refrigerate the gas to recover propane and heavier hydrocarbon liquid, and sweeten a slip stream of gas prior to distribution as either sales and/or transport gas, gas lift gas, re-injection gas or platform fuel gas.

There are five stages of compression; Vent Recovery Compression, Surge Tank Vapor (STV) Compression, First Stage Main Gas Compression, Second Stage Main Gas Compression, and Gas Injection Compression. The first stage of compression, (Vent Recovery Compressor) takes gas at essentially atmospheric pressure and compresses it to an intermediate pressure of 15 psig. Other intermediate or interstage pressures are 72 psig (STV Discharge), 325 psig (First Stage Discharge), 1100 psig (Second Stage Discharge), and 2976 psig (Gas Injection Discharge). All compressors are electric motor driven reciprocating machines totaling 13,800 hp.

- Vent Recovery Compressor: A single Vent Recovery Compressor compresses all vapors from the 1 psig vent recovery header and the glycol regenerator. This compressor is a 50 hp rotary vane type with a discharge pressure of approximately 15 psig and a capacity of 0.5 mmscfd.

- Surge Tank Vapor (STV) Compressors: Two 100 percent STV Compressors compress the 15 psig gas from the emulsion surge tank, the gas from the vapor recovery compressor, and the acid gas from the amine regenerator to a discharge pressure of approximately 72 psig. The compressors are balanced opposed, two cylinder, single stage 900 RPM, 250 hp with a capacity of 1.04 mmscfd each. The STV compressor system includes two inlet coolers and a common suction scrubber.

- First and Second Stage - Main Gas Compressors: Four 25 percent First and Second Stage These compressors are six throw balanced opposed 900 RPM reciprocating type machines rated at 3500 hp each. Four cylinders (throws 3 through 6) serve as the "First Stage" Main Gas Compressor while the remaining two cylinders (throws 1 and 2) serve as the "Second Stage" Main Gas Compressor.

  The First Stage of compression takes suction from the production separators and the STV compressors at approximately 72 psig and compresses the gas to a discharge pressure of approximately 325 psig in two stages without intercooling. Cylinders 4 and 6 compress the gas from 72 psig to approximately 175 psig while cylinders 3 and 5 compress the gas from 170 psig to 325 psig. The First Stage Main Gas Compressors are equipped with dual inlet coolers with a common suction scrubber and with dual outlet coolers with a common discharge scrubber. The total capacity of the first stage system is approximately 56 mmscfd (75 mmscfd with future unit addition). The compressed gas is conditioned by dehydration and refrigerated for heavy ends removal prior to returning to the Second Stage Main Gas Compressors.

The Second Stage Main Gas Compressors compress the treated gas stream from 300 psig to 1100 psig in two stages without intercooling. The first stage of compression (cylinder 1) discharges at approximately 630 psig while the second stage (cylinder 2) discharges at 1100 psig. The Second Stage Main Gas Compressors are equipped with a common suction scrubber and dual outlet coolers with a common discharge scrubber. The total capacity of the second stage compression is approximately 51 mmscfd (68 mmscfd with future unit addition). The high pressure gas from this system supplies the platform gas lift system, gas sales and/or transport and the gas injection system.

- Gas Injection Compressors: The Gas Injection Compressors consist of two 50% four cylinder, balanced opposed reciprocating type 900 RPM compressors rated at 1500 hp each. Gas is compressed from 1100 psig to approximately 2976 psig in a single stage of compression. The total capacity of the injection compressors is 55 mmscfd. The high pressure gas from this system supplies the platform gas lift system as well as the gas injection system.

Gas from the main gas compressor first stage is conditioned by routing the compressed gas through a TEG contactor for dehydration followed by a depropanizer to remove recoverable propane and heavier hydrocarbons. NGL's recovered in the gas conditioning process are routed to the emulsion pipeline.

Dehydration and Glycol Regeneration: A standard TEG contactor dehydrates saturated gas from the Main Gas Compressor First Stage Discharge Scrubber to a design water dew point of minus 40°F. A filter upstream of the TEG Contactor helps control carryover of heavy hydrocarbons and particulates into the Contactor. Rich TEG from the Contactor is regenerated in the Glycol Still by heating the glycol solution to approximately 400°F with heating oil and stripping with a small amount of fuel gas. Lean TEG from the regenerator reboiler is cooled and pumped back to the Contactor for dehydration of the gas stream. A sidestream of lean glycol is continuously recycled through a charcoal filter to remove hydrocarbons.

Depropanizer: The Depropanizer recovers propane and heavier natural gas liquids (NGLs) from the dehydrated gas by cold temperature separation and fractionation. The dehydrated gas from the TEG Contactor is cooled in the Gas/Gas Exchanger and combined with the Depropanizer overhead vapor prior to further cooling in the Depropanizer Condenser. The Depropanizer operates as a conventional fractionator with a bottoms reboiler and refrigerated overhead partial condenser. The Depropanizer bottoms product is subcooled and pumped to emulsion pipeline pressure before commingling with the crude emulsion. Reflux for the Depropanizer is generated by chilling the rich gas from the Gas/Gas Exchanger and Depropanizer overhead vapor in the Depropanizer Condenser. The conditioned gas leaving the Depropanizer Reflux Accumulator is heat exchanged with the dehydrated rich gas in the Gas/Gas Exchanger and then flows to the second stage of the Main Gas Compressors.

2.1.8 *Gas Sweetening and Sulfur Recovery*: The platform contains a gas sweetening unit to produce fuel gas for use on the platform. There is no sulfur recovery system on the platform.

Sweet fuel gas for the platform in produced from sour conditioned gas drawn off at the suction of the second stage of the Main Gas Compressors. The gas is sweetened in an Amine Contactor by countercurrent contacting with MDEA (Amine) solution to selectively remove H_2S. The sweetened gas is scrubbed and heated to 100°F and routed to the fuel gas system. The acid gas removed in the amine regeneration system is recycled to the STV compressor.

2.1.9 *Vapor Recovery System*: All vessels and tanks on the platform with the exception of nine atmospheric vessels (mainly chemical and lube storage) and three sumps (Open Drain, Skim Pile and Wellbay) are connected to either the gas gathering, vapor recovery or the flare header systems.

Vessels that operate at pressures above 50 psig relieve excess pressure through the PSVs to the flare header. The remaining vessels and tanks that are connected to one of the recovery systems normally relieve through a PSV or vent directly to one of the vapor recovery systems that recycle gas to the platform gas compression system. The pressure relief valves only open during emergency situations or mandatory testing.

2.1.10 *Heating and Refrigeration*: The platform contains a recirculating hot oil system heated by a direct fired process heater and a mechanical refrigeration system that utilizes refrigerant compressors.

The Heating Oil System provides a heat source for the Glycol Regeneration Reboiler, the Amine Regeneration Reboiler, the Depropanizer Reboiler, Well Cleanup Separator, Closed Drain Sump, and Monterey Production Heater. The system consists of a heating oil surge tank, circulating pumps, supply and return headers, and a direct fired process heater. The system transfers heat from the heater to the process exchangers by circulating heating media (Exxon Caloria HT43).

A closed cycle mechanical refrigeration system is used to cool and partially condense vapors in the Depropanizer and Glycol Contactor overhead. Process side temperatures range from minus 15°F to minus 30°F. The refrigeration system is designed for a minimum refrigerant evaporator temperature of minus 40°F.

2.1.11 *Waste Gas Flaring:*

2.1.11.1 *Flare System Design*: The Flare System is made up of the flare headers, a flare scrubber, a flare tip and an igniter panel. The flare system collects the discharged fluids from all equipment relief valves, emergency back pressure control valves, and manual blowdown valves. The flare scrubber separates any liquid from the gas prior to burning at the flare tip. The separated liquid is automatically dumped into the closed drain system. Three constantly burning pilots evenly spaced around the flare tip provide a continuous ignition source for the discharged gases in all wind conditions.

Pressure relief devices are installed, as required by industry code design specifications on all applicable pressure vessels, tanks, sumps, compressors, pumps, piping systems, pipelines and other designated components.

The flare measuring system on the platform consists of four separate flow meters to determine the volume of gas sent to the flare. The main line to the flare contains a high flow (FE-134-1) and low flow (FE 134-2) meter. The separate vent recovery system relief to the flare contains a low flow (FE 134-3) meter as well as low flow (FE 134-4) meter measuring the flowrate from the auxiliary distance pieces. The range of operations of the meters on the main line is from a maximum of 76.4 mmscfd to a minimum of 0.068 mmscfd while the vent recovery relief meter has a range of 0.56 to 0.001 mmscfd.

2.1.11.2 *Planned Flaring Scenarios*: Planned flaring events include, but are not limited to the following: pipeline blowdown, platform turnaround, MMS safety tests, planned equipment shutdown and startup, well cleanup/blowdown and valve leakage. The four most common or routine planned flaring scenarios that occur on the platform are described below:

(1) During startup of specific units (i.e., the compression system), a manual purge may be performed to remove air from the system. This minimizes the possibility of having combustible gas mixtures in the process. This purge is performed with sweet fuel gas.

(2) During the shut down of gas compressors and other pieces of equipment, Shut Down Valves (SDV's) close and automatic blow down valves (BDV's) open releasing pressure from the system. This is performed to augment safety as well as to comply with codes and regulations.

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

(4) During normal operations, sweet fuel gas is continuously used to purge the flare headers to prevent in-leakage of air.

2.1.11.3 *Unplanned Flaring Scenarios*: Unplanned flaring events on the platform most commonly originate from platform safety trips and compressor safety trips that cause equipment shutdowns.

2.2 Support Systems

2.2.1 *Pipelines*: Pipelines present on the platform are as follows:

- 12 inch export produced gas pipeline to Platform Hondo.
- 12 inch import produced gas pipeline to Platform Heritage.
- 20 inch import emulsion pipeline from Platform Heritage.
- 14 inch import emulsion pipeline from Platform Hondo.
- 20 inch export emulsion pipeline to the Exxon LFC treating plant.
- 12 inch import produced water return pipeline from the Exxon LFC treating plant.

2.2.2 *Power Generation*: Electrical power is provided to supply the platform electrical demand from the Exxon Las Flores Canyon Cogeneration facility or Southern California Edison (SCE) through a submarine cable from shore. The platform has a 900 kW, 1344 bhp diesel engine driven generator set to provide standby power for lighting, UPS system, control room pressurization fans, survival capsules, quarters building, instrument/utility air compressor and fire water pump in case of a failure of power from shore.

The platform has a 120 Volt AC Uninterruptible Power Supply System (UPS). The system consists of two 125 Volt DC, 600 Amp battery chargers, one 125 Volt DC battery bank, one 50 KVA static inverter, one automatic static transfer switch, one manual bypass switch and various distribution panel boards.

The system supplies regulated and transient-free 120 volt AC power to the essential loads such as the Distributed Control System (DCS), fire and gas alarm system, nav-aids, platform emergency lights, communication equipment and crane obstruction lights. The system is sized to provide continuous power for eight (8) hours to the Nav-Aids system and for one (1) hour to all other loads after failure of normal power has occurred.

All loads are electrically driven with the exception of the following diesel driven equipment: one pedestal crane, one firewater pump, two air compressors used primarily for abrasive blasting, the emergency generator, and the auxiliary drilling generator and associated well service equipment. In addition, several air driven pumps are also operated on the platform.

2.2.3 *Crew Boats and Supply Boats*: Crew boats are used to transport personnel and equipment to and from the platform and currently average about 2-3 round trips per day between the platform and Ellwood pier.

Supply boats are utilized to transfer equipment and supplies to and from the platform and average, during normal production operations (i.e., no drilling or well repair) about one round trip per day between the platform and Port Hueneme. During periods of drilling or well repair, the supply boat frequency could increase by 3-4 round trips per week.

2.2.4 *Helicopters*: Helicopter use currently averages about 2-3 round trips per day between the platform and the Santa Barbara Airport.

2.3 Drilling Activities

2.3.1 *Drilling*: The drill rig on the platform is being used to complete the initial development drilling program that began in 1993. The rig is also used to perform well workover procedures. The rig, and related equipment, such as the drilling mud system, was specially designed for use on the platform. The mud equipment includes pumps, degasser, mud pits and related components. The mud fluid has an ROC content of less than 10 percent by weight. The major components on the drill rig, including the derrick and the superstructure, are maintained on the platform and are idle during non-drilling periods. The drilling rig and much of the associated equipment required for drilling are powered by electrical motors supplied from the platform systems. Emergency power is supplied from the 2,307 bhp diesel engine driven Auxiliary Drilling Generator.

2.3.2 *Well Workover*: Exxon periodically performs well workovers.

2.3.3 *Enhanced Recovery*: Enhanced oil recovery techniques are not currently employed on the platform.

2.4 Maintenance/Degreasing Activities

2.4.1 *Paints and Coatings:* Maintenance painting on the platform is conducted on a continuing basis. Normally only touch-up and equipment labeling/tagging is done with cans of spray paint. Solvents are also used as coating thinners.

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 normally scheduled to occur as part of an integrated SYU operation that takes into account both offshore and onshore requirements. Major pieces of equipment such as gas compressors undergo maintenance as specified by the manufacturer. Maintenance of critical components is carried out during planned turnarounds according to the requirements of Rule 331 (*Fugitive Emissions Inspection and Maintenance*). The emissions associated with planned process turnarounds are incorporated in the emissions category for planned flaring.

2.6 Other Processes

Exxon 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 10.4 for a complete listing of all permitted and exempt emission units.

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3.0 Regulatory Review

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

3.1 Rule Exemptions Claimed

☞ APCD Rule 202 (*Exemptions to Rule 201*): Exxon has requested a number of exemptions under this rule. An exemption from permit, however, does not necessarily grant relief from any applicable prohibitory rule. The following exemptions were approved by the APCD:

- Section F.1.e for three (3) escape capsules (two rated at 55 bhp and one rated at 30 bhp).
- Section F.1.d for one emergency electrical generator driven by a diesel-fired piston internal combustion (IC) engine rated at 1344 bhp, one firewater pump driven by a diesel-fired piston IC engine rated at 430 bhp, one firewater pump rated at 525 bhp and one auxiliary drilling generator driven by diesel-fired piston IC engine rated at 2,307 bhp.
- Section D.6 (*De Minimis*). As of November 6, 1998, Exxon has not documented any de minimis changes at Platform Harmony.
- Section V.1 for one anti-foam storage tank.
- Section V.3 for three compressor lube oil storage tanks.
- Section L.1 for thirty-six (36) heat exchangers.
- Section L.3 for two refrigerant compressors.
- Section V.2 for one diesel fuel #2 storage tank with a 3,200 gallon capacity.
- Section U.2.a for a remote reservoir cold solvent cleaner.

☞ 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 less stainless steel tubing fittings.
- Section B.3(c) for PRDs vented to a closed system.
- Section B.3(c) for components totally enclosed or contained.
- Section B.2.b for components buried below the ground.
- Section B.3.b for components handling liquids or gases with ROC concentrations less than 10 percent by weight.

- Sections F.1, F.2 and F.7 for components that are unsafe-to-monitor, as documented and established in a safety manual or policy, and with prior written approval of the Control Officer.

☞ APCD Rule 325 (*Crude Oil Production and Separation*): The following equipment are exempt from the requirements of Sections D.1 and D.2 pursuant to Section B.3:

- Drill Deck Drains Settling Tank (ABJ-417)
- Wellbay Drain Sump (ABH-405)
- Open Drain Sump (ABH-406)
- Skim Pile (ABH-416)

The following equipment are exempt from the requirements of Sections D, E, F.4 and H pursuant to Section B.5:

- Closed Drain Sump (MBH-132)
- Emulsion Surge Tank (MBH-110)
- Amine Sump (MBH-170)

☞ 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. Therefore, those engines listed above under the Rule 202 exemption are not required to comply with Rule 333.

☞ APCD Rule 359 (*Flares and Thermal Oxidizers*): Under Section D.1.b, Exxon 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. 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 Harmony 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}: Exxon is operating Platform in compliance with the requirements of this regulation.

3.2.3 40 CFR Part 60 {*New Source Performance Standards*}: None of the equipment in this permit are subject NSPS requirements.

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*}: This facility is not currently subject to the provisions of this Subpart. However, compliance will be assessed once an applicable MACT standard is promulgated.

3.2.6 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998. Compliance with this rule is not required until the next Part 70 permit renewal or significant permit revision.

3.2.7 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to Platform Harmony. Table 3.1 lists the federally-enforceable APCD promulgated rules that are "generic" and apply to Platform Harmony. 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 Exxon's Part 70 Operating Permit application. Table 3.4 includes the adoption dates of these rules.

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

3.3 Compliance with Applicable State Rules and Regulations

3.3.1 Division 26. Air Resources {California Health & Safety Code}: The administrative provisions of the Health & Safety Code apply to this facility and will be enforced by the 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 Harmony are required to conform to these standards. Compliance will be 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.

3.4 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 Harmony. 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: The last facility inspections occurred on February 4, 1999. The inspector reported that the facility was in compliance with all APCD rules and PTO conditions. 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 Harmony:

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, Exxon is operating in compliance with this rule.

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for which a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the flare, the Central Process Heater and all diesel-fired piston internal combustion engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be 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. This rule does not apply to the platform since it is not included in the OCS Air Regulation.

Rule 305 - Particulate Matter, Southern Zone: Platform Harmony 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, the Central Process Heater and all diesel-fired IC engines on the platform. Improperly maintained diesel engines have the potential to violate this rule. Compliance will be 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 Harmony 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. Further, the APCD has not recorded any odor complaints from this facility.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted on Platform Harmony 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 Harmony 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 Central Process Heater is expected to be in compliance with the gaseous fuel limit as determined by an in-line hydrogen sulfide analyzer for the natural gas and fuel analysis documentation for the propane. 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. Exxon will be 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. Exxon has stated that there are 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 will be 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. Exxon will be 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. Exxon will be 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. Exxon will be required to maintain records to ensure compliance with this rule. Solvents used during operations (e.g., for degreasing and wipe cleaning) will be 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 are 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 Harmony.

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 Exxon SYU 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. An in-line hydrogen sulfide analyzer is required on the fuel gas line to the Central Process Heater to ensure compliance with permitted emission limits and Rule 311.

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 Exxon 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. Exxon has submitted a Fugitive Inspection and Maintenance Plan and received final APCD approval of the Plan on July 15, 1994. Ongoing compliance with the many provisions of this rule will be assessed via platform inspection by APCD personnel using an organic vapor analyzer and through analysis of operator records. Platform Harmony 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. However, per Section B.1.b any engine exempt from the requirement to obtain a permit under Rule 202 is also exempt from this rule (see Section 3.1 above). The diesel-fired pedestal crane engine on Platform Harmony is subject to the NO_x standards under Section D.4 of 8.4 g/bhp-hr or 796 ppmvd at 15 percent oxygen. Compliance with the emission standards was documented by a source test conducted on May 9-13, 1994. The crane test resulted in a NO_x concentration of 465 ppmvd at 15 percent oxygen. The source test report (#032-582) was submitted on June 17, 1994 and approved by the APCD on July 15, 1994. Ongoing compliance is achieved through implementation of the APCD-approved Maintenance Plan (submitted on 6/29/94 and approved on 6/29/94) required under Section E and through biennial source testing.

Rule 342 - Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters: This rules sets emission standards for external combustion units with a rated heat input greater than 5.0 MMBtu/hr. Platform Harmony has a Central Process Heater rated at 27.200 MMBtu/hr. The NO_x and CO emission standards of this rule are 30 ppmv and 400 ppmv (or 0.036 lb/MMBtu and 0.297 lb/MMBtu) respectively. Compliance is met by the use of low-NO_x burners. Ongoing compliance is achieved through biennial source testing.

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 vessel to which this rule applies is the emulsion surge tank. Ongoing compliance with this rule will be achieved through the section F and G reporting and recordkeeping requirements of the rule.

Rule 346 - Loading of Organic Liquids: This rule applies to the transfer of organic liquids into an organic liquid cargo vessel. For this rule only, an organic liquid cargo vessel is defined as a truck, trailer or railroad car and, as such, this rule does not affect OCS sources.

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

Rule 359 - Flares and Thermal Oxidizers: This rule applies to flares for both planned and unplanned flaring events. 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. A methyl diethanolamine sulfur treating unit which reduces the sulfur content of a portion of the platform produced gas will provide the flare with purge and pilot gas (445 scfh - planned flaring) that is within the limits of this rule (sulfur is limited to 80 ppmv by prior agreements). For all other planned emissions associated with platform flaring volumes, Exxon 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 Harmony is in compliance with this section.

§ D.3 - Flare Minimization Plan: This section requires sources to implement flare minimization procedures so as to reduce SO_x emissions. The Planned Flaring volume is 63 million standard cubic feet per month. Exxon has fully implemented their Flare Minimization Plan.

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

a. Is not the result of neglect or disregard of any air pollution control law or rule or regulation;

b. Is not the result of an intentional or negligent act or omission on the part of the owner or operator;

c. Is not the result of improper maintenance;

d. Does not constitute a nuisance as defined in Section 41700 of the Health and Safety Code;

e. Is not a recurrent breakdown of the same equipment.

Rule 603 - Emergency Episode Plans: Section "A" of this rule requires the submittal of *Stationary Source Curtailment Plan* for all stationary sources that can be expected to emit more than 100 tons per year of hydrocarbons, nitrogen oxides, carbon monoxide or particulate matter. Exxon submitted such a plan on July 23, 1994. This Plan was updated on January 24, 1997.

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 Variances: Exxon has not sought variance relief from APCD or permit requirements.

3.5.2 Violations: As of January 1999, three Notice of Violations (NOVs) were issued since the original permit was issued:

NOV No. 3999: Violation of Rule 323. Issued 4/5/95. Specifically, use of non-compliant coatings - exceeding the ROC emission standard. Resolved Date: 06/26/1995.

NOV No. 5015: Violation of Rule 331. Issued 7/11/95. Specifically, failure to repair a fugitive I&M component (greater than 50,000 ppmv) within 2 days of leak discovery. Resolved Date: 9/17/1995.

NOV No. 5990: Violation of Rule 331. Issued 12/17/98. Specifically, exceeded the maximum number of allowable leaks for major gas leaks (greater than 10,000 ppmv) for the inspection period. The leak found was greater than 50,000 ppmv. Resolved Date: 2/17/1999.

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

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 310: Odorous Org. Sulfides	All emission units	Emission of organic sulfides
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.

Generic Requirements	Affected Emission Units	Basis for Applicability
RULE 318: Vacuum Producing Devices – Southern Zone	All systems working under vacuum	Operating pressure
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 353: Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.
RULE 505.A, B1, D: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	Exxon – SYU 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	Exxon – SYU 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, 9-2, 9-3, 10-1, 10-2, 11-1, 11-2, 11-3, 11-4, 12-1, 12-2, 12-3	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 342: Control of Oxides of Nitrogen from Boilers, Steam	EQ Nos. 2-1, 2-2	Central Process Heater rated over 5 MMBtu/hr

Generators and Process Heaters		
RULE 359: Flares and Thermal Oxidizers	EQ No. 3-1	Flaring

Table 3.3 - Non-Federally-Enforceable APCD Rules

Requirement	**Affected Emission Units**	**Basis for Applicability**
RULE 210: Fees	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

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 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 No.	Rule Name	Adoption Date
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 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

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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 Harmony consist of diesel-fired piston internal combustion engines, the flare relief system and the central process heater. Primary power on the platform is supplied by an Exxon onshore cogeneration plant via a subsea power cable to the platform.

4.2.1 *Piston Internal Combustion Engines:* All platform internal combustion engines are diesel-fuel fired. The largest source of IC engine emissions is the pedestal crane. Other stationary IC engines on the platform rated over 100-bhp include two portable compressor engines used primarily for abrasive blasting, a drilling rig emergency electrical generator, one production emergency generator, and two emergency fire water pumps. The only IC engines rated at or less than 100 bhp are three escape capsules. 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 following calculation methodology is similar for all stationary IC engines:

$$ER = [(EF \ x \ BHP \ x \ BSFC \ x \ LCF \ x \ HPP) \div 10^6]$$

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)
	LCF =	liquid fuel correction factor, LHV to HHV
	HPP =	operating hours per time period (hrs/period)

The emission factor is an energy based value using the higher heating value (HHV) of the fuel. As such, an energy based BSFC value must also be based on the HHV. Manufacturer BSFC data are typically based on lower heating value (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 require conversion.

Crane engine: The pedestal crane is driven by a Detroit Diesel Model 8V-92TA engine rated at 450 bhp. This engine is not equipped with emission controls. The emission factors for PM_{10}, CO and ROC are based on USEPA AP-42, Table 3.3-1 (10/96) and the SO_x emission factor is based on mass balance. The NO_x emission factor is based on Rule 333 limits. Per AP-42, PM is assumed to equal PM_{10}. The results of source testing for this engine since September 4, 1994 are summarized in Attachment 10.2. The engine complies with the Rule 333 limits of 8.4 g/bhp-hr or 796 ppmv at 15 percent oxygen.

Portable air compressor engines: There are two portable air compressors used primarily for abrasive blasting each driven by a Cummins diesel-fired engine rated at 230 bhp. These engines are not equipped with emission controls. The emission factors for PM_{10}, CO and ROC are based on USEPA AP-42, Table 3.3-1 (10/96) and the SO_x emission factor is based on mass balance. The NO_x emission factor is based on Rule 333 limits. Exxon has not demonstrated compliance with Rule 333 and is prohibited from their use until compliance has been demonstrated.

The IC engines on the platform are not equipped with diesel fuel flow metering devices. All IC engines are equipped with non-resettable hour meters. The actual engine usage is logged during each time the engine is fired. Emissions are calculated using total elapsed run time, the maximum rated engine bhp rating and BSFC data (from Table 5.1-1) to determine the number of gallons consumed per unit time. Ongoing compliance with Rule 333 will be accomplished by quarterly inspections per Section E of this rule and biennial source testing.

4.2.2 *External Combustion Equipment*: The only external combustion equipment on Platform Harmony is the central process heater. The results of source testing for this heater since September 4, 1994 are summarized in Attachment 10.2. The ROC and PM emission factors are based on USEPA, AP-42 Table 1.4-2 (3/98). Per AP-42, PM_{10} is assumed to equal PM. The SO_x emission factor is based on mass balance. The NO_x and CO emission factor is based on the Rule 342 limits of 30 ppmv and 400 ppmv at 3 percent oxygen (0.036 lb/MMBtu and 0.297 lb/MMBtu). This unit is equipped with an orifice meter connected to the Distributed Control System for fuel monitoring purposes. The pollutant emission rates for this equipment will be determined by the permitted emission factors (lb/MMBtu) and fuel usage rates. Periodic analysis of the fuel gas will be conducted to determine the HHV and sulfur content of the fuel gas.

Propane (HD-5 specification) fuel may also be fired as a backup fuel when the natural gas supply has been interrupted. The NO_x and CO emission factors are based on Rule 342 limits. ROC and PM emission factors are based on USEPA, AP-42 Table 1.4-1 (3/98) – the emission factor basis is the same as natural gas on a heat input basis. Per AP-42, PM_{10} is assumed to equal PM. The SO_x emission factor is based on mass balance using the Gas Processors Association standard for HD-5 (123 ppmw).

4.2.3 *Flare Relief System*: The flare relief system consists of a header that connects to various PSVs on production and test vessels, compressors, glycol system and pigging vessels. The flare is a Kaldair model EAL-602 with a design heat release of 3820 MMBtu/hr .

Planned and unplanned flaring events occur on the platform. Planned events include purge and pilot requirements. NO_x, CO and ROC emission factors are based on USEPA AP-42, Section 13.5

(9/91). SO_x emissions are based on mass balance calculations. The PM emission factor is based on SBCAPCD Flare Study – Phase I Report (7/91). The PM_{10}/PM ratio is assumed to equal 1.0. The ROC/TOC ratio is assumed to equal 0.86.

The H_2S concentration of the purge and pilot gas is continuously monitored by a Houston Atlas H_2S detector located on the amine sweetening unit.

The flare header is equipped with a Fluid Components LT81A Gas Mass Flow Meter that is capable of detecting a minimum flow rate of 1,503 scfh. As such, there is no practical method for assessing flow rates below 1,503 scfh. Based on EPA and CARB's data reporting guidelines, a value of half the minimum detection limit is assumed to be "continuous" planned flaring. The H_2S concentration of the "continuous" planned flare gas is assumed to be 20,000 ppmv which corresponds to the anticipated average H_2S concentration of the platform produced gas. Other planned flaring sulfur levels will be determined by gas detector tubes (or equivalent APCD-approved method). Unplanned flaring is exempt from the sulfur standards of Rule 359.

The emissions for both planned and unplanned flaring events are calculated. The SO_x emission factor is determined using the equation: (0.169)(ppmv S)/(HHV). The calculation methodology for the flare emissions is:

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

<u>where</u>:	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)

To meet the requirements of Rule 359, Exxon uses purge and pilot gas that complies with the rule limit of 239 ppmv and has obtained exemption approval to exceed the sulfur limits for all other planned flaring activities.

4.3 Fugitive Hydrocarbon Sources

Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been quantified using empirical models (Tecolote Report, 1986). The equation from Model B is utilized. The uncontrolled emission factors are taken from APCD Policy & Procedure 6100.061 (9/25/98). The number of emission leak-paths (including pump and compressor seals and excluding all exempt components) were determined by the operator and verified by APCD staff by a site check of a representative number of P&IDs. The calculation methodology for the fugitive emissions is:

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

<u>where</u>:	ER =	emission rate (lb/period)
	EF =	ROC emission factor (lb/clp-day)
	CLP =	component leak-path (clp)
	CE =	control efficiency

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

An emission control efficiency is credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of a APCD-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements. Unsafe to monitor components are not eligible for I&M control credit. Component leak-paths that are monitored on a quarterly basis receive a control efficiency of 80 percent. Component leak-paths that are monitored to a LDAR threshold of 500 ppmv (designated as E500) receive a control efficiency of 85 percent. Component leak-paths that are monitored to a LDAR threshold of 100 ppmv (designated as E100) receive a control efficiency of 90 percent.

Ongoing compliance is determined in the field by inspection with an organic vapor analyzer and verification of operator records.

4.4 Crew and Supply Vessels

Platform Harmony is serviced by both crew and supply boats. Crew boats are used to transport personnel and light supplies between Ellwood Pier and the platform. Supply boats are used to transport equipment and supplies, between Port Hueneme and the platform. Crew boat main engines are controlled to reduce NO_x emissions through turbocharging, 4 degree timing retard and intercooling. Supply boat main engines are controlled to reduce NO_x emissions through turbocharging, 4 degree timing retard and enhanced intercooling.

For crew and supply boats, Exxon has identified two types of vessels. One type is for dedicated project usage and the main engines are controlled for NO_x. These are denoted as Dedicated Project Vessels (DPV). The other type is used as a spot-charter, and the main engines may be controlled or uncontrolled for NO_x. The crew and supply boat spot-charter trips are limited to 10 percent of actual crew boat trips. Compliance is based on a comparison of the actual fuel use.

The crew boat M/V Broadbill is used for emissions liability calculations as the typical crew boat. This boat is equipped with four 510 bhp main diesel-fired IC engines (Detroit Diesel 12VA71). Auxiliary diesel-fired engines on this boat include two 131 bhp diesel-driven generators (Detroit Diesel 3-71). These auxiliary engines are not controlled for NO_x.

The supply boat Sea Tide is used for emissions liability calculations as the typical supply boat. This boat is equipped with two 1,200 bhp main diesel-fired IC engines (DD 12V149 DDEC). Auxiliary diesel-fired engines on this boat include two 200 bhp diesel-driven generators (DD 8V-71), one 200 bhp bow thruster (DD 6-71). These auxiliary engines are not controlled for NO_x.

The permit is assessing emission liability based 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 0.20 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 NO_x main engine 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 is assessed through emission source testing (see Attachment 10.2 for a summary of all test results since 1994). Ongoing compliance is assessed through implementation of a APCD-approved Boat Monitoring and Reporting Plan. This Plan is required to follow the APCD *Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document (dated June 21, 1991 and subsequent updates). The requirements include: fuel usage meters on the main and auxiliary engines, a Global Positioning System (or equivalent location device) and a data gathering system. Alternative data collection and reporting methods that are equivalent in accuracy and reliability may be proposed by Exxon as part of the Boat Monitoring and Reporting Plan. Total mileage from Platform Harmony to Port Hueneme is greater than 25 miles.

In addition, a permanently assigned emergency response vessel (i.e., the *Clean Seas II*) is associated with Platform Harmony along with a small Exxon owned boom boat (the *MonArk)*. The engines on these vessels are uncontrolled. The total engine horsepower, including auxiliary engines, is 1,770 bhp. Emissions liability is assigned in a prorated fashion among the eleven 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.

4.5 Sulfur Treating/Gas Sweetening Unit

Platform Harmony is equipped with a methyl diethanolamine gas sweetening unit. The purpose of this unit is to remove hydrogen sulfide from the produced gas for use in the central process heater and the flare purge and pilot. The maximum treating capacity of this unit is 1.5 mmscfd at 1.5 percent H_2S (or 0.75 mmscfd at 3.0 percent H_2S). This is adequate to supply the flare purge and pilot (445 scfh) and the central process heater maximum fuel requirement (650,000 scfh). The acid gas from this system is recycled to the STV compressors. This system is equipped with a Houston Atlas H_2S analyzer and process controls to ensure that compliance with Rules 311 and 359 is achieved, as well as the permit limit of 80 ppmv.

4.6 Tanks/Vessels/Sumps/Separators

Tanks: Platform Harmony has one diesel fuel storage tank, a drilling deck drains settling tank and several miscellaneous tote tanks (e.g., corrosion inhibitor storage tank, methanol storage tank and tote tanks) of various sizes (250-1500 gallons each). The portable tote tanks are used in lieu of 55-

gallon drums to deliver various chemicals to the platform including xylene, de-emulsifiers, corrosion inhibitors, and anti-foam. The diesel storage tank services the various IC engines on the platform and is not controlled. All these tank emissions are very small and are assumed to be less than 0.10 tpy (200 lb/yr). The detailed tank calculations for compliance will be performed using the methods presented in USEPA AP-42, Chapter 7.

The drill deck drains settling tank collect liquids from the drill deck and the wellbay sump and separates the solids from liquids and oil from water. The oil is routed to the open drain sump and the water to the skim pile. The skim pile vessel is covered but not connected to the vapor gathering system.

Vessels: Platform Harmony has many pressure vessels (e.g., production separators, a test separator, clean-up separator, test treater, emulsion surge tank, vent scrubber, and suction scrubbers). 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 a result of fugitive hydrocarbon leaks from valves and connections.

Sumps: There is an open and closed drain sump, a skim pile, amine sump and a wellbay drain sump on the platform. The closed drain sump and the amine sump are connected to the vapor recovery system. The remaining tanks are covered.

The tank and sump tank emissions are based on the CARB/KVB Report (*Emissions Characteristics of Crude Oil Production in California*, January 1983). The calculation is:

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

<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)

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 platform vapor recovery system is equipped with one electrically driven 50 bhp A-C Compressor Corp. compressor (Model 10GB) with a design capacity of 0.5 mmscfd. The compressed vapors are routed to the STV compressor for sales, injection or gas lift. The following equipment is connected to the vapor recovery system: glycol still, amine sump, glycol sump, closed drain, compressor distance pieces, and STV compressor discharge. All remaining major vessels are vented to the flare header.

4.8 Helicopters

Platform Harmony is serviced by helicopters, including a Bell 212/412, an Aero Star 355F-1 and a Bell 206L. The helicopters are primarily used for personnel transportation and emergencies. Each round trip usually originates and terminates at the Santa Barbara Airport and averages approximately forty-five minutes. Emission factors in units of "lb/hr" for different types of helicopters have been established for each operating mode based on the particular turbine engine used. These modes (idle, climb, cruise, and descent) make up the total cycle time for each trip segment. For Platform Harmony, there are two identical trip segments (Santa Barbara Airport to Platform Harmony and Platform Harmony to the Santa Barbara Airport). The emission rate per trip segment is calculated as:

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

<u>where</u>:

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 Harmony, the one trip segment is simply doubled to obtain an emission rate per trip. Emission tracking will be 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 Harmony:

Pigging: Pipeline pigging operations occur on the platform. These consist of an emulsion pipeline pig launcher to the LFC onshore facility, an emulsion pipeline pig receiver from Platform Hondo, an emulsion pipeline pig receiver from Platform Heritage, a gas pipeline pig launcher to Platform Hondo and a gas pipeline pig receiver from Platform Heritage. All pig launchers and receivers are connected to either the VRS or the flare header and are depressurized to this system after each use. The small amount of emissions which remain are vented to the atmosphere. Exxon has committed to maintain the remaining pressure at levels no greater than 1 psig. The calculation per time period is:

$$ER = [V_1\ x\ r\ x\ wt\ \%\ x\ EPP]$$

<u>where</u>:		
	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
	EPP =	pigging events per time period (events/period)

General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurs on Platform Harmony as part of normal daily operations and includes small cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming all the solvent used evaporates to the atmosphere. Additionally, there is one cold solvent degreasing unit located on Platform Harmony.

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 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 two compressor are diesel driven. 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}. PM_{10}/ PM ratio of 1.0 is assumed.

4.10 BACT/NSPS/NESHAP/MACT

Except as described below, none of the emission units at Platform Harmony are subject to best available control technology (BACT), NSPS or NESHAP provisions. MACT provisions have yet to be promulgated.

BACT has been triggered pursuant to modifications authorized under ATC 9640 for the installation of a skid-mounted natural gas compressor unit. Table 4.1 details the BACT requirements for Platform Harmony.

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. Table 4.2 details the Rule 331 BACT requirements for Platform Harmony.

As part of ATC 9827, Exxon voluntarily implemented BACT controls on the Heritage/Harmony gas pipeline topsides project in order minimize their offset liability. Table 4.3 documents the controls implemented.

4.11 CEMS/Process Monitoring/CAM

4.11.1 CEMS: There are no in-stack continuous emission monitoring systems used on Platform Harmony 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 APCDs' 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.

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, flare gas flow meters and hydrogen sulfide analyzers. Once these process monitors are in place, it is important that they be well maintained and calibrated to ensure that the required accuracy and precision of the devices are within specifications. At a minimum, the following process monitors will be required to be operated, calibrated and maintained in good working order:

- ☞ Crane Engine Diesel Fuel Meter
- ☞ Supply Vessel Diesel Fuel Meters (main and auxiliary/bow thruster engines)
- ☞ Crew Vessel Diesel Fuel Meters (main and auxiliary engines)
- ☞ Flare Header Flow Meters
- ☞ Hour Meters (crane engine, emergency generator engines, firewater pump engines, compressor engines)
- ☞ Hydrogen Sulfide Analyzer
- ☞ Central Process Heater Fuel Meter

To implement the above calibration and maintenance requirements, a *Process Monitor Calibration and Maintenance Plan* was required of Exxon. 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 judgement is utilized.

4.11.3 CAM: *Exxon – SYU Project* is a major source that is subject to the USEPA's Compliance Assurance Monitoring (CAM) rule (40 CFR 64). Any emissions unit at the facility with uncontrolled emissions potential exceeding major source emission thresholds for any pollutant is subject to CAM provisions. Exxon must submit a compliance plan to the APCD for this rule at the time of Part 70 permit renewal or before if the permit is reopened due to a significant permit change.

4.12 Source Testing/Sampling

Source testing and sampling are required in order to ensure compliance with permitted emission limits, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Table 4.4 details the pollutants, test methods and frequency of required testing. Exxon 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.

- ☞ Crane Engine and Compressor Engines
- ☞ Supply Boat Main Engines
- ☞ Crew Boat Main Engines
- ☞ Central Process Heater

At a minimum, the process streams below are required to be sampled and analyzed on an annual basis. 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 the 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. Exxon's source test plan shall include the specific sampling and analytical methods required to obtain the process stream data above.

TABLE 4.1 – BACT REQUIREMENTS FOR GAS COMPRESSOR SKID UNIT NO. CZZ-306

Component Type	Technology	Performance Standard
Valves	Low Emission Design Valves (e.g., bellows seal valves, valves with graphite or teflon packing, machined stems or "stem finish", injectable valve stem packing with teflon or graphite rings).	100 ppm as methane above ambient, monitored per EPA Reference Method 21.
Connectors (Flanges/ Connections)	Flanges: graphitic gaskets rated at 150% of actual process pressure and process temperature; Non-flange connections: none specified.	100 ppm as methane above ambient, monitored per EPA Reference Method 21.
Compressor Seals	Each compressor cylinder is equipped with two sealed compartment distance pieces which surround the reciprocating compressor cylinder's power-shaft. The inner distance piece is purged with blanket gas and connected to vapor recovery; the outer distance piece is connected to the flare, with no supplemental blanket gas purge. The outer distance piece has an atmospheric seal system surrounding the reciprocating power-shaft.	100 ppm as methane above ambient, monitored per EPA Reference Method 21, if possible to monitor.
Relief Valves	Routed to vapor recovery or flare.	Vapor recovery or flare/thermal oxidation system to have a capture/destruction efficiency of 98% by weight.
Repairs Timelines	Repairs to any BACT valve, flange/connection or compressor seal (if monitoring possible) showing between 100 ppm and 10,000 ppm above ambient to be made on the schedule detailed in Rule 331 for minor leaks. Repairs to any BACT valve, flange/connection or compressor seal (if monitoring possible) showing above 10,000 ppm above ambient to be made on the schedule(s) detailed in Rule 331.	
Fugitive I&M Program	Leak detection and repair program consistent with the requirements of the *Fugitive Hydrocarbon Emissions Components* Condition of this permit.	

TABLE 4.2 – RULE 331 BACT REQUIREMENTS

Component	Technology	Performance Standard
Valve: ID No. HA-4150 (Thred-o-let at thermowell, ½ inch threaded fitting)	New gasket at threaded fitting.	100 ppm as methane above ambient, monitored per EPA Reference Method 21.

TABLE 4.3
EMISSION CONTROL REQUIREMENTS FROM ATC 9827
Topsides Installation (Heritage to Harmony Pipeline) - Platform Harmony
Fugitive Hydrocarbon Component Control Technologies

Component Type	Technology	Performance Standard
Valves	Low Emission Design Valves (e.g., bellows seal valves, valves with graphite or teflon packing, machined stems or "stem finish", injectable valve stem packing with teflon or graphite rings).	100 ppm as methane above ambient, monitored per EPA Reference Method 21.
Connectors (Flanges/ Connections)	Flanges: graphitic gaskets rated at 150% of actual process pressure and process temperature; Non-flange connections: none specified.	100 ppm as methane above ambient, monitored per EPA Reference Method 21.
Repairs Timelines	Repairs to any new valve or flange/connection (if monitoring possible) showing between 100 ppm and 10,000 ppm above ambient to be made on the schedule detailed in Rule 331 for minor leaks. Repairs to any new valve or flange/connection (if monitoring possible) showing above 10,000 ppm above ambient to be made on the schedule(s) detailed in Rule 331.	
Fugitive I&M Program	Leak detection and repair program consistent with the requirements of the *Fugitive Hydrocarbon Emissions Components* Condition of this permit.	

TABLE 4.4 - SOURCE TEST REQUIREMENTS

Emission Points	Pollutants/ Parameters	Test Methods
- Crane Engine - Crew Boat Main Engines - Supply Boat Main Engines - Portable Compressor Engines - Central Process Heater	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 emissions tests to consist of three 40-minute runs. Crane engine tests to consist of three 20-minute runs. Crane engine, portable compressors and central process heater to be tested at maximum safe load. Crew and supply boat main engines to be tested at cruise load. Crew boat test runs may be shortened if the boat is used on normal trips to/from the platform. The engine RPM and boat speed shall be recorded during each test run. Subsequent testing may be required if required loads are not achieved.

b. The specific project crew and 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 crew and one supply boat shall be tested annually. Crane and portable compressor engines and central process heater 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). Section 5.2 details the permitted emissions for each emissions unit. Section 5.3 details the overall permitted emissions for the facility based on reasonable worst-case scenarios using the potential-to-emit for each emissions unit. Section 5.4 provides the federal potential to emit calculation using the definition of potential to emit used in Rule 1301. Section 5.5 provides the estimated emissions from permit exempt equipment and also serves as the Part 70 list of insignificant emission. Section 5.6 provides the net emissions increase calculation for the facility and the stationary source. In order to accurately track the emissions from a facility, the APCD uses a computer database. Attachment 10.3 contains the APCD's documentation for the information entered into that database.

5.2 Permitted Emission Limits - Emission Units

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

⇒ Nitrogen Oxides (NO_x) [2]
⇒ Reactive Organic Compounds (ROC)
⇒ Carbon Monoxide (CO)
⇒ Sulfur Oxides (SO_x) [3]
⇒ Particulate Matter (PM) [4]
⇒ 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. In the table, the last column indicates whether the emission limits are federally enforceable. Those emissions limits that are federally enforceable are indicated by the symbol "FE". Those emissions limits that are APCD-only enforceable are indicated by the symbol "A". Emissions data that are shown for informational purposes only are not enforceable (APCD or federal) and are indicated by the symbol "NE".

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

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

[4] 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:

- Pedestal crane engine
- Both air compressor engines
- Central Process Heater
- Flare Purge and pilot
- Planned continuous flaring (minus the purge/pilot volumes)
- Spot charter uncontrolled crew and supply boats
- Generator engines on crew and supply boats provide half of maximum engine rating
- Bow thruster on supply boat does not operate during peak hour
- Fugitive components
- Oil pig launcher/receivers
- Gas pig launcher/receiver
- Open/Closed drain sumps, wellbay sump, skim pile, amine sump
- Drill deck settling tank, emulsion surge tank
- Solvent usage
- Degreaser usage

Quarterly and Annual Scenario:

- Pedestal crane engine
- Both air compressor engines
- Central process heater
- Flare Purge and pilot
- Planned continuous flaring
- Planned intermittent (other) flaring
- Unplanned flaring
- Fugitive components
- Controlled and uncontrolled (spot-charter) supply boats
- Generator engines on crew and supply boats provide half of maximum engine rating
- Bow thruster on supply boat
- Controlled and uncontrolled (spot-charter) crew boats
- Oil pig launcher/receivers
- Gas pig launcher/receiver
- Open/Closed drain sumps, wellbay sump, skim pile, amine sump
- Drill deck settling tank, emulsion surge tank
- Solvent usage
- Degreaser usage

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 list these exempt emissions units and the expected emissions. These are emission estimates only. They are not limitations.

5.6 Net Emissions Increase Calculation

This facility's contribution to the stationary source's net emissions increase since November 15, 1990 (the day the federal Clean Air Act Amendments was adopted in 1990) is based on the following NSR permit actions since December 5, 1991:

(a) ATC 9640 (12/18/96)
PTO 9640 (11/12/97)

ROC = 0.13 lb/hr, 3.05 lb/day, 0.14 tpq, 0.56 tpy

(b) ATC 9827 (1/21/98)

ROC = 1.25 lb/hr, 3.87 lb/day, 0.08 tpq, 0.29 tpy

(c) ATC/PTO 10170 (crew and supply boat Phase I permit)

See NEI Section of ATC/PTO 10170 for complete discussion/analysis. NEI increase for the short term emission increases is attributable to the LFC permit ATC/PTO 10172. The table below documents the NEI calculation for this platform, but is not used since it is lower than the LFC permit, however if the LFC permit ATC/PTO 10172 boat increase were not to exist than the NEI increase documented in ATC/PTO 10170 would apply. There was no increase in long term NEI (or PTE) emissions from the Phase I crew and supply boat project.

The NEI contribution from Platform Harmony is:

ROC	=>	1.38 lb/hr, 6.92 lb/day, 0.24 tpq, 0.85 tpy
NO_x	=>	0.00 lb/hr, 0.00 lb/day, 0.00 tpq, 0.00 tpy
CO	=>	0.00 lb/hr, 0.00 lb/day, 0.00 tpq, 0.00 tpy
SO_x	=>	0.00 lb/hr, 0.00 lb/day, 0.00 tpq, 0.00 tpy
PM	=>	0.00 lb/hr, 0.00 lb/day, 0.00 tpq, 0.00 tpy

PM_{10} => 0.00 lb/hr, 0.00 lb/day, 0.00 tpq, 0.00 tpy

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Table 5.1-1

Table 5.1-2

Table 5.1-3

Table 5.1-4

Table 5.2

Table 5.3

Table 5.4

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6.0 Air Quality Impact Analyses

6.1 Modeling

Air quality modeling was not required for the issuance of this OCS operating permit. Modeling was performed for Exxon's onshore portion of the SYU Expansion Project in 1987. The air impacts from the operation of Platform Harmony were addressed in ATC 5651 (11/87) and the results are summarized in PTO 5651 (1/99).

6.2 Increments

An increment analysis was not required for the issuance of this OCS operating permit. An increment analysis was performed for Exxon's onshore portion of the SYU Expansion Project in 1987. The air impacts from the operation of Platform Harmony were addressed in ATC 5651 (11/87) and the results are summarized in PTO 5651 (1/99).

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 Platform Harmony.

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7.0 CAP Consistency, Offset Requirements and ERCs

7.1 General

The *Exxon - SYU Project* stationary source is located in an ozone nonattainment area. Santa Barbara County is nonattainment for both the federal and state ozone ambient air quality standards. In addition, the County is 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 towards attainment of federal and state ambient air quality standards. Under APCD regulations, any modifications at Platform Harmony (or the *Exxon - SYU 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. The offset threshold levels for these pollutants (55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day) already are exceeded.

7.2 Clean Air Plan

Santa Barbara County does not meet the current hourly federal ambient ozone standard of 0.12 ppm or the state hourly ambient ozone standard of 0.09 ppm. The APCD has submitted the 1998 Clean Air Plan (Final, 12/98) to the USEPA through the State of California Air Resources Board. The 1998 CAP, if approved by the USEPA, will be incorporated into the California State Implementation Plan (SIP). The CAP demonstrates a Rate-of-Progress and how the county will attain the ambient ozone standards by 1999 through the application of emission controls on all pollution sources.

7.3 Offset Requirements

The *Exxon - SYU Project* stationary source requires emission offsets. Offsets are required for all permitted emissions at the onshore LFC processing plant and for all NEI increases that occurred on the OCS Platforms since being subject to the requirements of the OCS Air Regulation (40 CFR Part 55). The specific offset requirements for Platform Harmony are detailed in Table 7.1 for ROC and Table 7.2 for SO_x.

7.4 Emission Reduction Credits

Platform Harmony does not generate or provide emission reduction credits.

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Table 7.1

Table 7.2

8.0 Lead Agency Permit Consistency

A Final Development Plan for the Santa Ynez Unit/ Las Flores Canyon project was approved by the Santa Barbara Planning Commission on September 15, 1987. This Plan included permit conditions XII-3, 5, 8, 11 and 17 which required Exxon to fully mitigate adverse air quality impacts of the project which would affect the county. In part, these conditions required the following measures: full mitigation of all NO_x and ROC construction and operation emissions associated with the SYU project (including OCS emission sources); installation of Ambient Air Monitoring and Continuous Emission Monitoring Stations, and submittal of an air quality related Emergency Episode Plan. These requirements are included as part of ATC 5651 issued on November 19, 1987 and all subsequent permits that supersede that permit.

The United States Department of Interior's Mineral Management Service approved the *Development and Production Plan* for Platform Harmony on September 20, 1985.

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9.0 Permit Conditions

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

9.A Standard Administrative Conditions

The following federally-enforceable administrative permit conditions apply to Platform Harmony. 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 Exxon shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: PTO 9101*]

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 9101*]

A.3 **Defense of Permit.** Exxon 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. Exxon 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 Exxon of its obligation under this condition. The APCD shall bear its own expenses for its participation in the action. [*Re: PTO 9101*]

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 Exxon as required by Rule 210. [*Re: PTO 9101, 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, Exxon 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 9101*]

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 9101*]

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. [*Re: PTO 9101*]

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

(a) the County of Santa Barbara in Final Development Plan Permit 87-DP-32cz and any subsequent modifications;

(b) the Santa Barbara County Air Pollution Control District in Authority to Construct No. 5651, Permit to Operate No. 5651, 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 9101*]

A.9 **Compliance with Department of Interior Permits.** Exxon shall comply with all air quality control requirements imposed by the Department of the Interior in the Development and Production Plan approved for Platform Harmony on September 20, 1985 and any subsequent modifications. Such requirements shall be enforceable by the APCD. [*Re: PTO 9101*]

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 working days of the emergency. The "notice of emergency" shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. [*Re: 40 CFR 70.6(g), APCD Rule 1303.F*]

A.12 **Compliance Plans.**

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

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

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

A.13 **Right of Entry.** The Regional Administrator of USEPA, the Control Officer, or their authorized representatives, upon the presentation of credentials, shall be permitted to enter upon the premises where a Part 70 Source is located or where records must be kept:

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

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

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

[*Re: APCD Rule 1303.D.2*]

A.14 **Severability.** The provisions of this Permit to Operate are severable and if any provision of this Permit to Operate is held invalid, the remainder of this Permit to Operate shall not be affected thereby. [*Re: APCD Rules 103 and 1303.D.1*]

A.15 **Permit Life.** The Part 70 permit shall become invalid five 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 earlier than 18 months and not later than 6 months before the date of the permit expiration. Upon submittal of a timely and complete renewal application, the Part 70 permit shall remain in effect until the Control Officer issues or denies the renewal application. [*Re: 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 6 months 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 approved 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 15 and February 15, 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 a permit is reopened, the expiration date does not change. Thus, 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)*]

A.22 **Permit Shield.** The rules and regulations listed in Table 1.1 of this permit have been specifically identified as non-applicable to Platform Harmony. This shield shall remain in effect until expiration of this permit or re-opening and re-issuance of this permit. [*Re: 40 CFR 70.6(f), APCD Rule 1303.E.4*]

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 Harmony 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).** Exxon shall not discharge into the atmosphere from any single source of emission any air contaminants for a period or periods aggregating more than three minutes in any one hour which is:

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

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

Compliance shall be determined by APCD staff certified in visual emission evaluations. [*Re: APCD Rule 302*].

B.3 (Deleted)

B.4 **PM Concentration - South Zone (Rule 305).** Exxon 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.5 **Specific Contaminants (Rule 309).** Exxon 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.6 **Odorous Organic Sulfides (Rule 310).** Exxon shall not discharge into atmosphere H_2S and organic sulfides that result in a ground level impact beyond the Exxon property boundary in excess of either 0.06 ppmv averaged over 3 minutes and 0.03 ppmv averaged over 1 hour. [*Re: APCD Rule 310*]

B.7 **Sulfur Content of Fuels (Rule 311).** Exxon shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd 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.8 **Organic Solvents (Rule 317).** Exxon shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on Exxon's compliance with Condition C.8 (*Solvent Usage*) of this permit. [*Re: APCD Rule 317*]

B.9 **Vacuum Producing Devices or Systems – Southern Zone (Rule 318).** Exxon 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.10 **Solvent Cleaning Operations (Rule 321).** Exxon 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 Exxon's compliance with Condition C.8 (*Solvent Usage*) of this permit as well as APCD inspections. [*Re: APCD Rule 321*]

B.11 **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 Exxon's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 322*]

B.12 **Architectural Coatings (Rule 323).** Exxon shall comply shall comply with the coating ROC content and handling standards listed in Section D of Rule 323 as well as the Administrative requirements listed in Section F of Rule 323. Compliance with this condition shall be based on Exxon's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 323*]

B.13 **Disposal and Evaporation of Solvents (Rule 324).** Exxon 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 Exxon's compliance with Condition C.8 (*Solvent Usage*) of this permit and facility inspections. [*Re: APCD Rule 324*]

B.14 **Continuous Emissions Monitoring (Rule 328).** Exxon shall comply with the requirements of Section C, F, G, H and I of Rule 328 for the fuel gas hydrogen sulfide analyzer. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as on-site inspections.

B.15 **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]

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 No.	Name
1-1	East Pedestal Crane (450 bhp)
1-2	Portable Air Compressor #1 (230 bhp)
1-3	Portable Air Compressor #2 (230 bhp)
1-4	Production Emergency Electrical Generator Engine (1344 bhp)
1-5	Drill Rig Emergency Electrical Generator Engine (2307 bhp)
1-6	Emergency Firewater Pump Engine (430 bhp)
1-7	Emergency Firewater Pump Engine (525 bhp)

(a) Emission Limits: Mass emissions from the East Pedestal Crane and Portable Air Compressor IC 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) *East Pedestal Crane Engine* - Controlled emissions of NO_x from the East Pedestal Crane engine shall not exceed either 8.4 g/bhp-hr or 797 ppmv 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.

(ii) *Portable Compressor Engines* - Controlled emissions of NO_x from each Portable Compressor engine shall not exceed either 8.4 g/bhp-hr or 797 ppmv 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) *Liquid Fuel Sulfur Limit* - Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.20 weight percent as determined by APCD-approved ASTM methods.

(ii) *Fuel Use Limits* - Exxon shall comply with the following fuel limits:

- The East Pedestal Crane engine shall not use more than: 537 gallons per day; 24,491 gallons per quarter; 97,962 gallons per year of diesel fuel.

- The Portable Compressor engine #1 shall not use more than: 138 gallons per day; 12,556 gallons per quarter; 50,224 gallons per year of diesel fuel.

- The Portable Compressor engine #2 shall not use more than: 138 gallons per day; 12,556 gallons per quarter; 50,224 gallons per year of diesel fuel.

(iii) *Emergency Diesel IC Engine Use* - The diesel-fired IC engines driving the fire water pumps, drill rig emergency power generator and the production emergency power generator shall only be operated for testing or emergency purposes no more than 200 hours per calendar year each. Exxon shall install, operate and properly maintain a dedicated non-resettable elapsed-time meter on each of these engines. The drill rig emergency generator engines may be only used for the purpose of securing wells and allowing for the safe shut-down of platform operations. These engines may not be used to advance drilling or production operations. Exxon shall record in a log for each engine the following: ID number of the equipment; the number of operating hours on each day the engine is operated; and, the cumulative total monthly and annual hours.

(iv) *IC Engine Replacements* - Equivalent routine IC engine replacements do not require a permit revision. Exxon shall notify the APCD within 30 days of an equivalent routine replacement unless the replacement equipment is identical as to make and model and the replacement is routine, in which case such notification is not required. Permit revisions will be required for all other IC engine replacements.

(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.

(vi) *Portable Air Compressor Use* - Use of either portable air compressor is prohibited until full compliance with Rule 333 is demonstrated. Exxon must present a formal request to the APCD that documents how compliance with this rule has been and will continue to be maintained. Exxon shall obtain APCD written approval prior to operating these two engines.

(vii) *High Pressure Fuel Injectors* - If high pressure fuel injectors are used to comply with Rule 333 standards, then that injector type shall be used on the engine for the life of the engine except as noted below. Exxon may revert to the normal pressure fuel injectors if APCD-approved source testing shows that the Rule 333 standards are achieved.

(c) Monitoring: The following source testing and periodic monitoring conditions apply to the East Pedestal Crane and Air Compressor IC engines:

(i) *Fuel Meters* - The amount of fuel combusted in each engine shall be measured using permanently installed APCD-approved fuel meters dedicated to each engine. As an alternative to in-line fuel meters, Exxon may report individual engine hours of operation utilizing a APCD-approved elapsed time meter [5]. A monthly log shall be maintained that records the fuel usage (or hours of operation) of each engine.

(ii) *Inspection and Maintenance Plan (I&M Plan)* - Exxon 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, Section E. This Plan, and any subsequent APCD-approved revisions, is incorporated by reference as an enforceable part of this permit.

(iii) *Source Testing* - For each engine, Exxon shall perform source testing of air emissions and process parameters consistent with the requirement of Condition C.13 (*Source Testing*) and in accordance with the requirements of Rule 333.G.

(iv) *Fuel Data* - Exxon 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.

(vi) For each engine with timing retard, an APCD Form –10 (*IC Engine Timing Certification Form*) must be completed each time the engine is serviced.

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

(i) Daily, quarterly and annual fuel usage in units of gallons for the East Pedestal Crane and Portable Air Compressor engines.

(ii) The hours of operation for the fire water pump, drill rig emergency power generator and the production emergency power generator (by ID number). The log shall detail the

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[5] 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 will be used to determine the number of gallons of fuel consumed per time period.

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.H.

(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 9101, ATC/PTO 10037, 40 CFR 70.6*)

C.2 **Combustion Equipment – Central Process Heater.** The following equipment are included in this emissions unit category:

EQ No.	Name
2-1	Central Process Heater (27.200 MMBtu/hr) – Natural Gas Fired
2-2	Central Process Heater (27.200 MMBtu/hr) – Propane Fired

(a) Emission Limits: Mass emissions from the Central Process Heater 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) *NO_x Emissions* - Controlled emissions of NO_x from the Central Process Heater shall not exceed 30 ppmvd at 3 percent oxygen or 0.036 lb/MMBtu when fired on either natural gas or propane. Compliance shall be based on source testing.

(ii) *CO Emissions* - Controlled emissions of CO from the Central Process Heater shall not exceed 400 ppmvd at 3 percent oxygen or 0.297 lb/MMBtu when fired on either natural gas or propane. Compliance shall be based on source testing.

(b) Operational Limits:

(i) *Fuel Use Limits* - Exxon shall comply with the following operating limits:

- The Central Process Heater shall not use more than: 502,154 standard cubic feet per day; 45.822 million standard cubic feet per quarter; 183.286 million standard cubic feet per year of natural gas as fuel.

- The Central Process Heater shall not use more than: 64,659 standard cubic feet per day; 0.862 million standard cubic feet per quarter; 3.448 million standard cubic feet per year of propane gas as fuel.

(ii) *Fuel Gas Sulfur Limit* - The sulfur content of fuel gas combusted in the Central Process Heater shall not exceed 5 gr/100 scf (80 ppmv) total sulfur calculated as hydrogen sulfide at standard conditions. Compliance shall be based on in-line continuous monitoring. During amine system startups and shutdowns, the total sulfur content of the fuel shall be allowed to increase up to 239 ppmv as hydrogen sulfide at standard conditions. Exxon shall operate the amine based fuel gas sweetening system at all times when combusting fuel gas in the process heater when the fuel source is from a sour production well. The amine system need not operate if the fuel gas to be combusted in the process heater is obtained from a sweet production well containing less than 80 ppmv total sulfur as hydrogen sulfide at standard conditions.

(iii) *Use of Propane as Fuel Gas* - Propane may be used as an auxiliary fuel gas to the Central Process Heater on a temporary basis only during times when the supply of produced gas is interrupted or when the gas sweetening system is being repaired. 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).

(c) <u>Monitoring</u>: The equipment in this section are subject to all the monitoring requirements listed in APCD Rule 342.E, G and I. The test methods In Rule 342.H shall be used. In addition, Exxon shall:

(i) *Fuel Meters* - The amount of fuel combusted in the Central Process Heater shall be measured using permanently installed APCD-approved in-line fuel meter. Alternative methods for determining propane usage may be proposed by Exxon for APCD review and approval.

(ii) *Source Testing* - On a biennial schedule, Exxon shall source test the Central Process Heater according to Condition C.13 (*Source Testing*). More frequent testing may be required, as determined by the APCD, if full operating loads have not been achieved.

(iii) *Propane Fuel Data* - Exxon shall maintain documentation of the sulfur content and higher heating value (as determined by APCD-approved ASTM methods) of each propane fuel shipment as certified in the fuel suppliers billing vouchers.

(iv) *Natural Gas Fuel Data* – Exxon shall monitor the sulfur content of the natural gas fuel using an in-line continuous 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. The readings from this analyzer shall be adjusted upward to take into account the average non-hydrogen sulfide reduced sulfur compounds in the fuel gas (if any). Exxon shall implement the APCD-approved *Fuel Gas Sulfur Reporting Plan* for the life of the project. This Plan shall detail: the monitoring equipment and CEM protocol procedures, the adjustments to the hydrogen sulfide readings due to non-hydrogen sulfide reduced sulfur compounds and the reporting methods for compliance with the applicable limits. Exxon shall submit the lab analyses reports to the APCD.

(d) Recordkeeping: The equipment listed in this section are subject to all the recordkeeping requirement listed in Rule 342.I. In addition, Exxon shall:

(i) *Natural Gas Fuel Use* - Daily, quarterly and annual fuel use for the Central Process Heater in units of standard cubic feet.

(ii) *Sulfur Content* - A monthly log of the total sulfur content of the natural gas and propane combusted as fuel gas.

(iii) *Propane Fuel Gas Use* - Record in a log each usage of propane in a APCD-approved format and maintain documentation of the sulfur content of each fuel shipment as certified in the fuel suppliers billing vouchers.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 342.J. 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 311, 342 and 1303, PTO 9101, ATC/PTO 10037, 40 CFR 70.6*)

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

EQ No.	Name
3-1	Flare (3,820 MMBtu/hr)

(a) Emission Limits: Mass emissions from the flare relief system listed above shall not exceed the limits listed in Tables 5.1-3 and 5.1-4. Notwithstanding the above and consistent with APCD P&P 6100.004, the short-term emission limits for *Planned - Other* and *Unplanned - Other* flaring categories in Table 5.1-3 shall not be considered as enforceable limits. Compliance with this condition shall be based on the operational, monitoring, recordkeeping and reporting conditions in this permit.

Continuous planned flaring emissions are assumed for the flare header based on one-half the minimum detection limit for the meter according to manufacturer minimum velocity detection limits (0.25 fps). Other than flare purge and pilot, this is the only continuous flaring allowed under this permit.

(b) Operational Limits:

(i) *Flaring Volumes* - Flaring volumes from the purge and pilot, planned continuous, planned other and unplanned other events shall not exceed the following volumes:

Flare Category	**Hourly** (10^3 scf)	**Daily** (10^3 scf)	**Quarterly** (10^6 scf)	**Annual** (10^6 scf)
Purge/Pilot	0.445	10.680	0.974	3.898
Planned Continuous	0.607	14.568	1.329	5.317
Planned Other			1.575	6.300
Unplanned Other			8.500	34.000

(ii) *Flare Purge/Pilot Fuel Gas Sulfur Limits* - The purge/pilot fuel gas combusted in the flare shall not exceed a total sulfur content of 80 ppmv. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iii) *Flare Planned Continuous Flaring Sulfur Limits* - The sulfur content of all gas burned as continuous flaring in the flare header shall not exceed 20,000 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.

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

(v) *Flaring Modes* - Exxon shall operate the flare consistent with APCD P&P 6100.004 (*Planned and Unplanned Flaring Events*). If Exxon is unable to comply with the infrequent planned and infrequent unplanned flaring limit of 4 events per year from the same processing unit or equipment type, then an ATC permit application shall be submitted to incorporate those emissions in the short-term (hourly and daily) emissions of Table 5.1-3.

(vi) *Rule 359 Planned Flaring Target Volume Limit* - Pursuant to Rule 359, Exxon shall not flare more than 63 million standard cubic feet per month during planned flaring events.

(c) Monitoring: The equipment in this section are subject to all the monitoring requirements listed in APCD Rule 359.G. The test methods In Rule 359.E. shall be used. In addition, Exxon 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 Exxon's *Process Monitor Calibration and Maintenance Plan* (approved 06/06/97 and all subsequent APCD-approved updates). An event is defined as any flow recorded by the flare header flow meters that exceeds the event flow rate thresholds listed below where the duration is 60 seconds or greater. During an event, any subsequent flows recorded by the flare header flow meter within 5 minutes after the flow rate drops below the minimum detection level of the meter shall be considered as part of the event.

FLARE HEADER	EVENT FLOW RATE THRESHOLD (scfh)	METER MINIMUM DETECTION LEVEL (scfh)
Flare (FE-134-2,-3)	1,503	1,503

All flaring not classified as an event pursuant to the above definition shall be aggregated as a single quarterly volume and recorded in the *Planned Other* flaring category. Notwithstanding the above definition of an event, continuous flaring is prohibited for the *Planned Other* and *Unplanned Other* flaring categories.

(ii) *Purge/Pilot Gas* - Exxon shall continuously monitor the purge/pilot fuel gas using H_2S analyzer. Exxon shall also perform annual total sulfur content and HHV measurements of the fuel gas using ASTM or other APCD-approved methods. Exxon shall utilize APCD-approved sampling and analysis procedures.

(iii) *Flaring Sulfur Content* - The hydrogen sulfide content of produced gas combusted during flaring events shall be measured on the schedule pursuant to the APCD-approved *Flare Gas Sulfur Reporting Plan* (approved 12/23/94 and all subsequent APCD-approved updates) using APCD-approved ASTM methods. On an annual basis, Exxon shall also measure the non-hydrogen sulfide reduced sulfur compounds and these values shall be added to the hydrogen sulfide measurements to obtain the total sulfur content. Exxon shall perform additional testing of the sulfur content and hydrogen sulfide content, using approved test methods, as requested by the APCD.

Exxon shall sample the flare header to determine the hydrogen sulfide content using sorbent tubes. To obtain the total sulfur content, Exxon shall add the prior year's non-hydrogen sulfide reduced sulfur compounds analysis result to the absorbent tube readings.

(iv) *Pilot Flame Detection* - Exxon 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, Exxon shall:

(i) *Flare Event Logs* - All flaring events shall be recorded in a log. The log shall include: date; duration of flaring events (including start and stop times); quantity of gas flared; total sulfur content; hydrogen sulfide content; high heating value; reason for each flaring event, including the processing unit or equipment type involved; the total heat input (MMBtu) per event; and, the type of event (e.g., Planned - Continuous LP, Unplanned - Other). The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year.

(ii) *Pilot/Purge Gas Volume* - The volume of pilot/purge fuel gas combusted in the flare shall be recorded on a weekly, quarterly and annual basis.

(iii) *Infrequent Flaring Events* - Exxon shall track and log the number of infrequent flaring events (as defined by APCD P&P 6100.004) from each processing unit or equipment type in a manner approved by the APCD.

(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 9101, 40 CFR 70.6*)

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

EQ No.	Name
	Gas/Light Liquid Service Components
4-1	Gas – Controlled
4-2	Gas – Unsafe
4-3	Gas – E500
4-4	Gas – E100
4-5	Gas – Exempt
	Oil Service Components
5-1	Oil – Controlled
5-2	Oil – Unsafe
5-3	Oil – E500
5-4	Oil – E100
5-5	Oil – Exempt

(a) Emission Limits: Mass emissions from the gas/light liquid service (sub-total) and oil service (sub-total) components 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 actual component-leakpath counts as documented through the 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 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 Exxon shall meet the following requirements:

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

(ii) *I&M Program* - The APCD-approved I&M Plan, *Fugitive Emissions Inspection and Maintenance Program for Platforms Harmony and Heritage* (7/15/94), for Platform Harmony 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) *Leakpath Count* - The total component-leakpath count listed in Exxon's most recent I&M component-leakpath inventory shall not exceed the component-leakpath sub-totals 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 main gas compressors, flare header, injection wells or other APCD-approved control device.

(v) *BACT* - Exxon shall apply BACT, as defined in Table 4.1 to all component- leakpaths in hydrocarbon service for Gas Compressor Skid Unit CZZ-306 for the life of the project.

(vi) *Rule 331 BACT* - The component-leakpaths in hydrocarbon service listed in Table 4.2 are subject to BACT requirements pursuant to Rule 331. BACT, as defined in Table 4.2, shall be implemented for the life of the project.

(vii) *ATC 9827 Emission Controls* - Exxon shall apply the emission controls defined in Table 4.3 to all component- leakpaths in hydrocarbon service for Heritage-to-Harmony Topsides Installation Project (ATC 9827) for the life of the project.

(viii) *E100 Requirements* - Component-leakpaths classified as emitters less than 100 ppmv ("E100") shall achieve a mass emission control efficiency of 90 percent. E100s are component-leakpaths defined as BACT pursuant to Regulation VIII and for which screening values are maintained at or below 100 ppmv as methane, monitored per EPA

Reference Method 21. For such E100s, screening values above 100 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(ix) *E500 Requirements* - Component-leakpaths classified as emitters less than 500 ppmv ("E500") shall achieve a mass emission control efficiency of 85 percent. E500s are defined as component-leakpaths associated with closed vent systems (e.g., vapor recovery systems) for which screening values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For such E500s, screening values above 500 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(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.

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

(i) *I&M Log* - Exxon 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.

For the purpose of the above paragraph, a leaking component is any component which exceeds the applicable limit (e.g., greater than or equal to 1,000 ppmv for minor leaks under Rule 331; greater than or equal to 100 ppmv for E100 components; greater than 500 ppmv for E500 components).

(ii) *Compressor Skid Unit CZZ-306 Requirements* - Exxon shall record the number of component-leak paths associated with the main gas compressor skid unit (CZZ-306) permitted under ATC 9640 and PTO 9640 as of the last day of each month, and the associated total ROC emissions for each month the compressor operates.

(iii) *Heritage-to-Harmony Pipeline Project Requirements* - Exxon shall record the number of component-leak paths associated with the Heritage-to-Harmony Pipeline Project permitted under ATC 9827 as of the last day of each month, and the associated total ROC emissions for each month this equipment operates.

(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* condition of this permit.

[*Re: APCD Rules 331 and 1303, ATC 9827, ATC 9640, PTO 9640, PTO 9101,* ATC/PTO 10037, *40 CFR 70.6*]

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

EQ No.	Name
Crew Boat	
6-1	Crew Boat Main Engines – Controlled
6-2	Crew Boat Main Engines – Uncontrolled
6-3	Crew Boat Auxiliary Engines
Supply Boat	
7-1	Supply Boat Main Engines – Controlled
7-2	Supply Boat Main Engines – Uncontrolled
7-3	Supply Boat – Bow Thruster
7-4	Supply Boat – Auxiliary Engines
Emergency Response Boat	
8-1	Emergency Response Main/Aux Engines

(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) *NO_x Emissions* - Controlled emissions of NO_x from each diesel fired main engine in each controlled crew and supply boat shall not exceed 337 lb /1000 gallons (8.4 g/bhp-hr). Uncontrolled spot charter crew and supply 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 this permit.

(ii) *Crew, Supply and Emergency Response Boat Stationary Source Maximum Permitted Emissions* - To more accurately define the *Exxon – SYU Project* Stationary Source's annual potential-to-emit (which is used to determine fees for Air Quality Plans (Rule 210.F)), crew boat, supply boat (including spot charters) and emergency response boat usage, in aggregate, associated with OCS Platforms Harmony and Heritage shall not exceed the annual emission limits shown in Table 5.2. These limits apply to the crew boats, supply boats and emergency response boats separately.

(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) *Crew Boat Main Engine Limits* - The crew boat main engines for Platform Harmony shall not use more than: 2,070 gallons per day; 71,128 gallons per quarter; 286,110 gallons per year of diesel fuel.

(ii) *Crew Boat Auxiliary Engine Limits* - The crew boat auxiliary engines for Platform Harmony shall not use more than: 156 gallons per day; 5,404 gallons per quarter; 21,615 gallons per year of diesel fuel.

(iii) *Supply Boat Main Engine Limits* - The supply boat main engines for Platform Harmony shall not use more than: 1,888 gallons per day; 60,317 gallons per quarter; 241,270 gallons per year of diesel fuel.

(iv) *Supply Boat Auxiliary Engine Limits* - The supply boat auxiliary engines (including the bow thruster) for Platform Harmony shall not use more than: 314 gallons per day; 9,521 gallons per quarter; 38,082 gallons per year of diesel fuel.

(v) *Emergency Response Boat Engine Limits* - The emergency response boat engines shall not use more than: 12,500 gallons per quarter; 50,000 gallons per year of diesel fuel. Exxon's allocation of allowable emergency response boat fuel usage for OCS Platforms Harmony, Heritage and Hondo shall not exceed: 1,137 gallons per quarter; 4,546 gallons per year of diesel fuel.

(vi) *Crew, Supply and Emergency Response Boat Stationary Source Operational Limits* - To more accurately define the *Exxon – SYU Project* Stationary Source's annual potential-to-emit (which is used to determine fees for Air Quality Plans (Rule 210.F)), crew boat, supply boat (including spot charters) and emergency response boat usage, in aggregate, associated with OCS Platforms Harmony and Heritage shall not exceed the annual fuel use limits shown in items (i), (ii), (iii), (iv) and (v) above. These limits apply to the crew boat main engines, crew boat auxiliary engines, supply boat main engines, supply boat auxiliary engines and emergency response boat engines separately.

(vii) *Spot-Charter Limits* - The number of allowable annual spot charter crew boat trips shall not exceed ten percent of the actual annual number of trips made by the Dedicated Project Vessel ("DPV") crew boats. The number of allowable annual spot charter supply boat trips shall not exceed ten percent of the actual annual number of trips made by DPV supply boats. Compliance shall be based on a comparison of the main engine fuel use for DPV and spot charter boats (i.e., the total main engine spot charter supply boat fuel use must be less than 10 percent of the total main engine DPV supply boat fuel use and the total main engine spot charter crew boat fuel use must be less than 10 percent of the total main engine DPV crew boat fuel use).

(viii) *Liquid Fuel Sulfur Limit* - Diesel fuel used by all IC engines shall have a sulfur content no greater than 0.20 weight percent as determined by APCD-approved ASTM methods.

(viii) *New/Replacement Boats* - Exxon may utilize any new/replacement project (DPV) boat without the need for a permit revision if that boat meets the following conditions:

(a) The main engines are of the same or less bhp rating; and
(b) The auxiliary engines and bow thruster engine are of the same or less bhp rating for the corresponding engine; and

(c) The NO_x, ROC, CO, PM and PM_{10} 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 APCD may require manufacturer guarantees and emission source tests to verify this NO_x emission standard.

The above criteria also apply to spot charter boats, except for the NO_x emission standard noted in (c) above. Any proposed new/replacement crew, supply or spot charter boat that does not meet the above requirements shall first obtain a permit revision prior to operating the boat.

Exxon 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.

Prior to bringing the boat into service for the first time, Exxon shall submit the information listed below to the APCD for any new/replacement crew and supply boat (including spot charters) that meets the requirements set forth in (a) – (c) above. 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.

(i) Boat description, including the type, size, name, engine descriptions and emission control equipment.

(ii) Details of the fuel monitoring system for main and auxiliary engines.

(iii) Engine manufacturers' data on the emission levels for the various engines and applicable engine specification curves.

(iv) Estimated fuel usage within state territorial waters on a daily basis.

(v) 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.

(c) <u>Monitoring</u>: Exxon shall comply with the requirements of the *APCD's Data Reporting Protocol for Crew and Supply Boat Activity Monitoring* document ("Boat Protocol", dated June 21, 1991 and any subsequent updates) for documenting and reporting boat activity, fuel usage and emissions. Boats reporting emissions based on cruise mode only shall not be required to comply with the Boat Protocol requirements for boat speed, engine rpm, mode or activity code.

Exxon shall equip all crew and supply boats servicing the Santa Ynez Unit platforms in support of drilling and production operations with in-line, continuous fuel meters, engine shaft revolution meters and Loran-C or equivalent location devices. These devices shall be connected to hardcopy records and computer disk outputs that are in a format acceptable to the APCD. These data shall demonstrate that the vessels are being operated consistent with the emission assumptions used in the issuance of this permit. Fuel use, engine rpm data, and Loran-C position must be collected while the boats are within state territorial waters. This data must be submitted in an APCD-approved format to the APCD as part of the *Compliance Verification Reports* condition of this permit

Exxon's *Boat Monitoring and Reporting Plan* shall follow the above-referenced Boat Protocol. Exxon shall fully implement their *Boat Monitoring and Reporting Plan* (7/16/99 and all subsequent APCD-approved updates) for the life of the project, and shall obtain APCD approval for any proposed updates or modifications to the Plan.

Exxon may use alternative methods (including location methods) for documenting and reporting boat activity, fuel usage and emissions, provided these methods are approved by the APCD as being equivalent in accuracy and reliability to those of the Boat Protocol.

Spot charter boats shall, at a minimum, track total fuel usage on a per day basis using APCD-approved procedures. These data shall be submitted in an APCD-approved format to the APCD.

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

(i) *Maintenance Logs* - For all main and auxiliary engines on controlled crew and controlled supply boats, maintenance log summaries that include details on injector type and timing, setting adjustments, major engine overhauls, and routine engine maintenance. These log summaries shall be made available to the APCD upon request. For each main and auxiliary engine with timing retard, an APCD Form –10 (*IC Engine Timing Certification Form*) must be completed each time the engine is serviced.

(ii) *Crew Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for crew boat main engines and auxiliary engines while operating within 25-miles of the platform, itemized by controlled and uncontrolled boats. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines

(iii) *Supply Boat Fuel Usage* - Daily, monthly, quarterly and annual fuel use for supply boat main engines and auxiliary engines while operating within 25-miles of the platform, itemized by controlled and uncontrolled boats. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.

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

(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 crew, supply and spot charter boat data required by the *Compliance Verification Reports* condition of this permit.:

If, at any time, the APCD determines that logs or reports indicate fuel use greater than the limits of Condition 9.C.5(b) of this permit, Exxon shall restrict its vessel activities to ensure that emissions do not exceed total quarterly emissions allowed in the permit, or shall submit an application for and obtain a permit providing additional offsets. Such offsets shall be in place no later than the start of the next quarter.

[*Re: APCD Rule 1303, PTO 9101,* ATC/PTO 10037, ATC/PTO 10170, *40 CFR 70.6*]

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

EQ No.	Name
9-1	Emulsion Pig Launcher (Export to Exxon LFC)
9-2	Emulsion Pig Receiver (Import from Platform Hondo)
9-3	Emulsion Pig Receiver (Import from Platform Heritage)
10-1	Gas Pig Launcher (Export to Platform Hondo)
10-2	Gas Pig Receiver (Import from Platform Heritage)

(a) Emission Limits: Mass emissions from the emulsion and gas pig receivers and 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 Exxon shall meet the following requirement:

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

(ii) *Pressure* - The pig receiver/launcher shall be depressurized to the vapor recovery system or flare prior to each hatch opening to the maximum extent feasible, but at no time shall the pig receiver/launcher hatch be opened when the pressure in the receiver/launcher is greater than 1 psig. Compliance shall be based on a test gauge or equivalent APCD-approved monitor installed to monitor the internal pressure of the receiver/launcher. Pressure readings shall be recorded prior to each opening of the receiver/launcher.

(iii) *Openings* - Access openings to the pig receiver/launcher shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the receiver/launcher. Prior to opening the pig receiver/launcher, Exxon shall purge the vessel with either sweet fuel gas (not to exceed 80 ppmv total sulfur content calculated as H_2S at standard conditions), nitrogen or water.

(c) Monitoring: Exxon shall monitor the pressure inside the pig receivers and launchers with an APCD-approved pressure test gauge or equivalent APCD-approved monitor installed to determine the internal pressure of the receiver/launcher.

(d) Recordkeeping: Exxon shall record in a log the date of each pigging operation and the pressure inside the receiver/launcher prior to each opening.

(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 9101,* ATC 9827, ATC/PTO 10037, *40 CFR 70.6*]

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

EQ No.	Name [6]	KVB Service
GROUP A UNITS		
11-1	Open Drain Sump (Vapor Recovery)	2º heavy oil
11-2	Wellbay Drain Sump (Vapor Recovery)	2º heavy oil
11-3	Skim Pile (Vapor Recovery)	2º heavy oil
11-4	Drilling Settling Tank (Vapor Recovery)	2º heavy oil
GROUP B UNITS		
12-1	Closed Drain Sump (Vapor Recovery)	2º heavy oil
12-2	Amine Sump (Vapor Recovery)	2º heavy oil
12-3	Emulsion Surge Tank	2º heavy oil
GROUP C UNITS		
13-1	Chemical Storage Tote Tanks	

(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: All process operations from the Group A equipment listed in this section shall meet the requirements of APCD Rule 325, Sections D.3, D.4, E, F and G. All process operations from the Group B equipment listed in this section shall meet the requirements of APCD Rule 325, Sections F.5 and F.6. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, Exxon shall:

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[6] Group A tanks are subject to Rule 325, but are exempt from Sections D.1 and D.2.
Group B tanks are subject to Rule 325, but are exempt from Sections D, E, F.4 and H.
Group C tanks are not subject to any Rule 325 requirements.

(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 maintain a minimum efficiency of 95 percent (mass basis). Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(iii) *Service Type Restrictions* - The KVB service type, as defined pursuant to APCD P&P 6100.060, for each Group A and Group B unit shall be restricted to the service type listed above or a service of a lesser emitting type (e.g., a secondary heavy oil sump may be used as a tertiary heavy oil sump).

(iv) *Rule 326 Applicability* - Exxon shall not use any tank, container or vessel that is subject to the requirements of Rule 326 without first obtaining an ATC permit from the APCD for such use.

(c) Monitoring: The equipment listed in this section are subject to all the monitoring requirements of APCD Rule 325.H (for Group A units only). The test methods outlined in APCD Rule 325.G shall be used, as applicable. In addition, Exxon shall:

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

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in APCD Rule 325.F. In addition, Exxon 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.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 325.I. 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 9101, 40 CFR 70.6*]

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

EQ No.	Name
14-1	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, Exxon 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* - Exxon may submit a Plan to the APCD for the disposal of any reclaimed solvent. If the Plan is approved by the ACPD, all solvent disposed of pursuant to the Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source. Exxon shall obtain APCD approval of the procedures used for such a reclamation Plan. The Plan shall detail all procedures used for collecting, storing and transporting the reclaimed solvent. Further, the ultimate fate of these reclaimed solvents must be stated in the Plan. The *Solvent Disposal/Recycle Plan* previously approved in 1997 does not satisfy the requirements of this condition.

(c) Monitoring: none

(d) Recordkeeping: Exxon 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 according to the APCD-approved *Solvent Reclamation Plan*, if such a plan is submitted by Exxon; whether the solvent is photochemically reactive; and, the resulting emissions of ROC to the atmosphere in units of pounds per month and the resulting emissions of photochemically reactive solvents to the atmosphere in units of pounds per month. Product sheets (MSDS or equivalent) detailing the constituents of all solvents shall be maintained in a readily accessible location at Platform Harmony.

(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 9101,* ATC/PTO 10037, *40 CFR 70.6*]

C.9 **Recordkeeping.** All records and logs required by this permit and any applicable APCD, state or federal rule or regulation shall be maintained for a minimum of five calendar years from the date of information collection and log entry at the platform. These records or logs shall be readily accessible and be made available to the APCD upon request. [*Re: APCD Rule 1303, PTO 9101, ATC 9640, PTO 9640, ATC 9827,* ATC/PTO 10037, *40 CFR 70.6*]

C.10 **Compliance Verification Reports.** Twice a year, Exxon shall submit a compliance verification report to the APCD. Each report shall document compliance with all permit, rule or other statutory requirements during the prior two calendar quarters. The first report shall cover calendar quarters 1 and 2 (January through June) and the second report shall cover calendar quarters 3 and 4 (July through December). The reports shall be submitted within 45 days of the end of the second and fourth quarters respectively. Each report shall contain information necessary to verify compliance with the emission limits and other requirements of this permit and shall document compliance separately for each calendar quarter. These reports shall be in a format approved by the APCD. Compliance with all limitations shall be documented in the submittals. All logs and other basic source data not included in the report shall be made 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. Exxon may use the Compliance Verification Report in lieu of the Emissions Inventory questionnaire if the format of the CVR is acceptable to the APCD's Emissions Inventory Group and if Exxon submits a statement signed by a responsible official stating that the information and calculations of quantifies of emissions of air pollutants presented in the CVR are accurate and complete to best knowledge of the individual certifying the statement. The report shall include the following information:

(a) *Internal Combustion Engines.*

(1) The daily, quarterly and annual fuel use for each pedestal crane and air compressor engine in units of gallons.

(2) The monthly and cumulative annual hours of operation for the fire water pump, drill rig emergency power generator and the production emergency power generator (by ID number).

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

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

(5) Documentation of any equivalent routine IC engine replacement.

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

(b) *Central Process Heater*.

(1) The daily, quarterly and annual fuel use for the Central Process Heater in units of standard cubic, broken down by natural gas and propane.

(2) The monthly total sulfur content of the natural gas and propane combusted as fuel gas.

(3) The annual fuel gas analyses required per the *Process Stream Sampling and Analysis* permit condition of this permit.

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

(c) *Flare*.

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

(2) 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.

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

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

(5) A copy of Flare Event Log for the reporting period.

(6) A copy of the Infrequent Flaring Events Log for the reporting period.

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

(1) Inspection summary.

(2) Record of leaking components.

(3) Record of leaks from critical components.

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

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

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

(7) Listing of components installed as BACT under APCD Rule 331 and Rule 802 as approved by the APCD.

(e) *Crew and Supply Boats*.

(1) Daily, quarterly and annual fuel use for the crew boat main engines and auxiliary engines while operating within 25 miles of Platform Harmony, itemized by controlled boat usage and uncontrolled boat usage. In addition, the fuel use must be summarized for all crew boats by main and auxiliary engines.

(2) Daily, quarterly and annual fuel use for the supply boat main engines and auxiliary engines (including the bow thruster engine) while operating within 25 miles of Platform Harmony, itemized by controlled boat usage and uncontrolled boat usage. In addition, the fuel use must be summarized for all supply boats by main and auxiliary engines.

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

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

(5) 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.

(6) 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.

(g) *Tanks/Sumps/Separators*.

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

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

(3) For the Group A and B units, list any changes in service type and provide an explanation of the change(s) that occurred.

(h) *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.

(i) *General Reporting Requirements*.

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

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

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

(4) 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.

(5) The produced gas, produced oil, fuel gas, and produced wastewater process stream analyses as required by condition 9.C.13 of this permit. Process stream analyses per Section 4.12

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

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

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

(9) 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).

(10) A copy of all completed APCD–10 forms (*IC Engine Timing Certification Form*).

(11) A copy of the Rule 202 De Minimis Log for the stationary source.

[*Re: APCD Rule 1303, PTO 9101, ATC 9640, PTO 9640, ATC 9827,* ATC/PTO 10037]

C.11 **BACT.** Exxon shall apply emission control and plant design measures which represent Best Available Control Technology (BACT) to the operation of Platform Harmony as described in Section 4.10 and Tables 4.1 and 4.2 of this permit. BACT measures shall be in place and in operation at all times for the life of the project. [*ATC 9640, PTO 9640*]

C.12 **Source Testing.** The following source testing provisions shall apply:

(i) Exxon shall conduct source testing of air emissions and process parameters listed in Table 4.4 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 crane engines, air compressors, and process heater shall be performed on a biennial schedule using June 1994 as the anniversary test date. The crane and portable compressor engines shall be loaded to the maximum safe load obtainable. Source testing of the crew and supply boat main engines shall occur on an annual basis using September of 1995 as the anniversary test date. The crew and supply boat main engines shall be tested at normal cruise speeds (minimum of 70 percent of maximum engine load). Only one crew boat and one supply boat shall be tested per year.

(ii) Exxon shall submit a written source test plan to the APCD for approval at least thirty (30) calendar days prior to initiation of each source test. The source test plan shall be prepared consistent with the APCD's *Source Test Procedures Manual* (revised May 1990 and any subsequent revisions). This plan shall include a technical evaluation on how these engines will be tested at the maximum safest load. Exxon 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.

(iii) 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 Exxon’s compliance status with mass emission rates in Section 5 and applicable permit conditions, and rules.. All APCD costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by Exxon as provided for by APCD Rule 210.

(iv) 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. 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.

[*Re: PTO 9101*]

C.13 **Process Stream Sampling and Analysis.** Exxon shall sample 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 9101*]

C.14 **Offsets - NSR.** Exxon shall offset all emissions of reactive organic compounds ("ROC") associated with the issuance of ATC 9640 and ATC 9827 as detailed in Section 7 and Table 7.1 of this permit. Emission reduction credits sufficient to offset the permitted quarterly ROC emissions shall be in place for the life of the project. [*Re: ATC 9640, PTO 9640, ATC 9827*]

C.15 **Offsets - Rule 359.** Exxon shall offset all emissions of oxides of sulfur ("SO_x") pursuant to Table 7.2 and Section 7 of this permit from the planned flaring of hydrocarbon gases on Platform Harmony as defined in APCD Rule 359. Emission reduction credits sufficient to offset the permitted quarterly SO_x emissions due to planned flaring shall be in place for the life of the project. [*Re: PTO 9101-01*]

C.16 **Process Monitoring Systems - Operation and Maintenance.** All platform process monitoring devices listed in Section 4.11.2 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. Exxon shall implement their *Process Monitor Calibration and Maintenance Plan* (06/06/97 and all APCD-approved updates thereof) 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 judgement is utilized. [*Re: PTO 9101*]

C.17 **Permitted Equipment.** Only those equipment items listed in Attachment 10.4 are covered by the requirements of this permit and APCD Rule 201.B. [*Re: APCD Rule 1303, PTO 9101, ATC 9640, PTO 9640, ATC 9827, ATC/PTO 10037*]

C.18 **Mass Emission Limitations**. Mass emissions for each equipment item (i.e., emissions unit) associated with Platform Harmony 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 9101, ATC 9640, PTO 9640, ATC 9827, ATC/PTO 10037, 40 CFR 70.6*]

C.19 **Facility Throughput Limitations.** Platform Harmony production shall be limited to a monthly average of 75,000 barrels of oil emulsion[7] per day and 75 million standard cubic feet of produced gas per day. Exxon 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 9101*]

C.20 **Emission Factor Revisions.** The APCD may update the emission factors for any calculation based on USEPA AP-42 or APCD P&P emission factors at the next permit modification or permit reevaluation to account for USEPA and/or APCD revisions to the underlying emission factors. Further, Exxon shall modify its permit via an ATC application if compliance data shows that an emission factor used to develop the permit's potential to emit is lower than that documented in the field. The ATC permit shall, at a minimum, adjust the emission factor to that documented by the compliance data consistent with applicable rules, regulations and requirements. [*Re: PTO 9101*]

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

C.21 **Abrasive Blasting Equipment.** All abrasive blasting activities performed on Platform Harmony shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. [*Re: APCD Rule 303, PTO 9101*]

C.22 **Produced Gas.** Exxon shall direct all produced gases to the main gas compressors, the flare header or other permitted control device when de-gassing, purging or blowing down any oil and gas well or 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 9101*]

C.23 **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, Exxon shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. Exxon shall implement their *Diesel Engine Particulate Matter (PM) Operation and Maintenance Plan* (12/23/94 and all APCD-approved updates thereof) for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules that Exxon will implement. Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgement 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 9101*]

C.24 **Emergency Episode Plan**. Six months prior to each scheduled triennial operating permit reevaluation date, Exxon shall review and update the Emergency Episode Plan for Platform Harmony and submit it for APCD approval. [*Re: APCD Rule 1303, PTO 9101*]

C.25 **Documents Incorporated by Reference.** The documents listed below, including any APCD-approved updates thereof, are incorporated herein and shall have the full force and effect of a permit condition for this operating permit. These documents shall be implemented for the life of Platform Harmony.

(i) *Fugitive Emissions Inspection and Maintenance Program for Platforms Harmony and Heritage* (approved 7/15/1994).

(ii) *Boat Monitoring and Reporting Plan* (approved 3/1/1995).

(iii) *Diesel Engine Particulate Matter (PM) Operation and Maintenance Plan* (approved 12/23/1994).

(iv) *Flare Gas Sulfur Reporting Plan* (approved 12/23/1994).

(v) *Process Monitor Calibration and Maintenance Plan* (approved 6/6/1997)

(vi) *Solvent Reclamation Plan* (upon approval).

(vii) *Rule 333 IC Engine Inspection and Maintenance Plan* (approved 06/29/1994).

(viii) *Rule 359 Flare Minimization and Monitoring Plan* (approved 12/22/1994).

[*Re: APCD Rules 317, 331, 333, 359, PTO 9101*]

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) This permit supersedes all previous APCD permits issued for Platform Harmony

(b) Permit Reevaluation Due Date: December, 2002

(c) Part 70 Operating Permit Expiration Date: December 2004

10.0 Attachments

10.1 Emission Calculation Documentation

10.2 Source Test Results Summary

10.3 IDS Database Emission Tables

10.4 Equipment List (Permitted and Exempt/Insignificant Equipment)

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10.1 EMISSION CALCULATION DOCUMENTATION

PLATFORM HARMONY

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

Reference A - Combustion Engines

- The maximum operating schedule is in units of hours.

- BSFC = 6,480 Btu/bhp-hr - East Crane
  - → energy based value using LHV
  - → Detroit Diesel 8V-92TA engine specification basis = 0.352 lb/bhp-hr

- BSFC = 6,500 Btu/bhp-hr - Portable Compressor Engines
  - → energy based value using LHV
  - → Cumins engine data: 11.47 gal/hr

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

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

- NO_x emission factor for crane engine based on Rule 333 limit (8.4 g/bhp-hr)
  - $\rightarrow E_{lb/MMBtu} = [(8.4 \text{ g/bhp}) \times (10^6)] \div [(6480 \text{ Btu/bhp-hr}) \times (1.06) \times (453.6)]$

- NO_x emission factor for compressor engine based on Rule 333 limit (8.4 g/bhp-hr)
  - $\rightarrow E_{lb/MMBtu} = [(8.4 \text{ g/bhp}) \times (10^6)] \div [(6500 \text{ Btu/bhp-hr}) \times (1.06) \times (453.6)]$

- SO_x emissions based on mass balance
  - $\rightarrow SO_x \text{ (as } SO_2) = (\%S) \times (\rho_{oil}) \times (20{,}000) \div (HHV)$

- Allowable sulfur content of 0.20 wt. % consistent with ATC 5651

- Crane engine operational limits: General Equation

  $Q = (BSFC) \times (bhp) \times (LCF) \times (\text{hours/time period}) \div (HHV, \text{Btu/gal})$

  See spreadsheet for calculation results

Reference B - External Combustion (Central Process Heater)

- The maximum operating schedule is in units of hours.

- CO emissions based on Rule 342 limit of 400 ppmvd at 3 percent O_2. Using USEPA NSPS f-factors (corrected to SBCAPCD standard condition), this equates to an emission factor of 0.297 lb/MMBtu.

- SO_x emission factor based on mass balance: (0.169)*(ppmv S)/(HHV).

- Allowable sulfur content of 80 ppmv based on ATC 5651 (11/87)

- Emissions based on heater maximum design throughput (27.2 MMBtu/hr) * emission factor.

- Sulfur content of the HD-5 propane: 123 ppmw. This equates to 165 ppmv S.

  $\rightarrow$ ppmv S = [(123 lb S/10^6 lb fuel) $\times$ (lb-mol S/32 lb S) $\times$ (lb fuel/21,669 Btu) $\times$ (379 scf /lb-mol) $\times$ (2524 Btu/scf fuel)]

- Process Heater operational limits: General Equation

  Q = (heat input, max rating) $\times$ (hours/time period) $\div$ (HHV, Btu/scf)

  See spreadsheet for calculation results

Reference C - 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.

- All flaring volumes based on Exxon application

- HHV = 1300 Btu/scf for all flare and purge and pilot gas (per Exxon application)

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

  $\rightarrow$ Flare meter: Fluid Components LT 81A mass flow detection
  $\rightarrow$ Minimum flow detection limit of flow element: 0.25 standard feet per second
  $\rightarrow$ Flare header outside: 18-inches (schedule 10)
  $\rightarrow$ Minimum detection limit: 1,503 scfh (3.292 mmscf/qtr, 13.166 mmscf/yr)

- Total planned continuous flaring is assumed to be one half the flare meter minimum detection limit (752 scfh). This value includes the purge fuel gas flow rate of 145 scfh. The pilot flow rate is 300 scfh. The purge value is backed out so as to perform correct sulfur oxide calculations.

- SO_x emissions from "planned continuous flaring": purge emissions (145 scfh) based on amine unit limit (80 ppmvd S); SO_x emissions from the remainder of "planned continuous flaring" (607 scfh) based on 20,000 ppmvd S.

- "Planned intermittent" (other) and "unplanned flaring" volumes based on Exxon application. SO_x emissions based 20,000 ppmv S.

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

- The same emission factors are used for all flaring scenarios, except for SO_x

- SO_x emissions based on mass balance

  $\rightarrow SO_x$ (as SO_2) = (0.169) × (ppmv S) ÷ (HHV)

Reference D - Fugitive Components

- The maximum operating schedule is in units of hours.

- 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 APCD's P&ID and platform review/site checks.

- Emission factors based on the SBCAPCD/Tecolote Report, *Modeling of Fugitive Hydrocarbon Emissions* (1/86), Model B as documented in APCD Policy & Procedure 6100.061 (9/98).

Reference E - Supply Boat

- The maximum operating schedule is in units of hours.

- Supply boat engine data based on Tidewater Marine's *Sea Tide*.

- Two 1,200 bhp main engines (i.e., 2,400 bhp), two 200 bhp generator engines, and one 325 bhp bow thruster engines are utilized. The engine bhp from the bulk transfer generator engine is not included, but emissions must be reported against the potential to emit.

- Main engine load factor based on APCD *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 of each engine at the same time.

- The APCD has standardized the total time a supply boat operates (per trip) within 25 miles of platform to 11 hours. A trip includes time to, from and at the platform. This is based on a typical trip consisting of: 8 hours cruise, 2 hours maneuver and 1 hour idle.

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

- Supply boat 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.

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

- Spot charter supply boat usage limited to 10 percent of actual annual DPV supply boat usage.

- Spot charter and Emergency Response vessels are uncontrolled for NO_x .

- Emissions from the Exxon MonArk boat are attributable to the Emergency Response emission liability category.

- 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, 1500 bhp engine}

- Uncontrolled NO_x emissions from spot charter supply and emergency response boat main engines based on an emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

  $\rightarrow EF_{NOx}$ = (14 g/bhp-hr) $\div$ (0.055 gal/bhp-hr) $\div$ (453.6 g/lb) $\times$ (1000)

- 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

  $\rightarrow SO_x$ (as SO_2) = (%S) $\times$ (ρ_{oil}) $\times$ (20,000) $\div$ (HHV)

- Sulfur content basis of 0.20 wt % is consistent with ATC/PTO 10037

- USEPA AP-42 emission factors converted to fuel basis using:

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

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

- Emergency response vessel liability is based on the assumption of a *Clean Seas* vessel currently servicing the waters off of Santa Barbara

- Emergency response vessel is permanently assigned to Platforms Henry, Hillhouse, A, B, C, Houchin, Hogan, Habitat, Hondo, Heritage, and Harmony. Vessel total bhp is 1,770 bhp. Short-term emissions from this vessel are not assessed. Long-term emissions are assessed equally amongst the eleven affected platforms.

- Emergency response vessel emissions calculated as an aggregate (main and auxiliary engines) using the uncontrolled supply boat emission factors. The long term hours of operating are back-calculated based on the fuel usage allocation for this platform of 4,546 gallons per year (50,000 gal/yr basis).

  $\rightarrow T_{yr} = \{(4{,}546 \text{ gal/yr}) \div (0.055 \text{ gal/bhp-hr} \times 1770 \text{ bhp} \times 0.65)\} = 72 \text{ hr/yr}$

- Main and auxiliary engine operational limits: General Equation

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

  see spreadsheet for calculated values

<u>Reference F - Crew Boat</u>

- The maximum operating schedule is in units of hours.

- Crew boat engine data based on C&C's *Broadbill.*

- Four 510 bhp main engines (i.e.; 2,040 bhp), and two 131 bhp auxiliary engines.

- Main engine load factor based on APCD *Crew and Supply Boat* study (6/87).

- Crew boat auxiliary engine provides half of total rated load.

- The total time a crew boat operates (per trip) is 3.7 hours. A trip includes time to, from and at the platform. This is based on a typical trip consisting of: 1.7 hours cruise, 1 hour maneuver and 1 hour idle.

- 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:

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

- 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}

- Uncontrolled NO_x emissions from spot charter crew boat main engines based on an emission rate of 14 g/bhp-hr. This emission factor equates to 561 lb/1000 gallons:

  $\rightarrow EF_{NOx} = (14 \text{ g/bhp-hr}) \div (0.055 \text{ gal/bhp-hr}) \div (453.6 \text{ g/lb}) \times (1000)$

- 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:
  $\rightarrow SO_x$ (as SO_2) = (%S) × (ρ_{oil}) × (20,000) ÷ (HHV)

- USEPA AP-42 emission factors converted to fuel basis using:
  $\rightarrow EF_{lb/1000\ gal} = (EF_{lb/MMBtu}) \times (19{,}300\ Btu/lb) \times (7.05\ lb/gal) \div (1000)$

- Main and auxiliary engine operational limits: General Equation

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

  see spreadsheet for calculated values

<u>Reference G - Pigging Equipment</u>

- Maximum operating schedule is in units of events.

- Gas and oil launcher and receiver volumes, pressures and temperatures based on application.

- All gas in launchers is blown down to the vapor recovery system or the flare relief system prior to opening the vessel to the atmosphere.

- The remaining vessel pressure is no greater than 1 psig (15.7 psia). The temperature of the remaining vapor in both vessels = 100°F

- The MW_{gas} = 23 lb/lb-mol (gas launcher) and MW_{oil} = 50 lb/lb-mol (oil launcher)

- Average ROC weight % = 0.33 (oil), 0.30 (gas)

- 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":
  $\rightarrow \rho =$ (P_{ves} × MW) ÷ (R × T), density of vapor remaining in vessel (lb VOC/acf)
  $\rightarrow$ EF = (ρ × ROC wt. %), (lb ROC/acf-event)

<u>Reference H - Sumps/Tanks/Separators</u>

- Maximum operating schedule is in units of hours.

- There are no oil/water separators on Platform Harmony.

- Emission calculation methodology based on the CARB/KVB report *Emissions Characteristics of Crude Oil Production Operations in California* (1/83) as documented in APCD P&P 6100.060.

- Calculations are based on surface area of emissions unit as supplied by the applicant.

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

- Controls (vapor recovery) are utilized only on the closed drain sump and the amine sump. The emission factors reflect a 95 percent control efficiency.

<u>Reference H - Solvents</u>

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

- Quarterly and annual emission rates per application. Daily number is annualized.

- Hourly emissions based on daily value divided by an average 24-hour day. Compliance with daily value based on monthly emissions divided by the number of days per month. Compliance with hourly data to be based on the monthly daily average divided by 24.

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10.2 Source Test Results Summary

The following table summarizes all source test performed for Exxon's Platforms Harmony, Hondo and Hondo since September 4, 1994 through the issuance of the public draft .

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10.3 IDS Database Emission Tables

Table 10.3-1
Permitted Potential to Emit (PPTE)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9101 - Platform Harmony						
lb/hour	130.52	26.79	30.22	9.25	8.92	8.65
lb/day	2,830.50	415.70	663.90	203.90	190.70	184.70
tons/qtr	42.07	14.35	21.38	21.52	4.21	4.09
tons/year	167.30	57.34	85.38	86.02	16.74	16.30

Table 10.3-2
Facility Potential to Emit (FPTE)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9101 - Platform Harmony						
lb/hour	130.52	26.79	30.22	9.25	8.92	8.65
lb/day	2,830.50	415.70	663.90	203.90	190.70	184.70
tons/qtr	42.07	14.35	21.38	21.52	4.21	4.09
tons/year	167.30	57.34	85.38	86.02	16.74	16.30

Table 10.3-3
Federal Facility Potential to Emit (Federal FPTE)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9101 - Platform Harmony						
lb/hour	130.52	18.66	30.22	9.25	8.92	8.65
lb/day	2,830.50	220.60	663.90	203.90	190.70	184.70
tons/qtr	42.07	5.45	21.38	21.52	4.21	4.09
tons/year	167.30	21.74	85.38	86.02	16.74	16.30

Table 10.3-4
Facility Net Emission Increase Since 1990 (FNEI-90)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9101 - Platform Harmony						
lb/hour	0.00	1.38	0.00	0.00	0.00	0.00
lb/day	0.00	6.92	0.00	0.00	0.00	0.00
tons/qtr	0.00	0.24	0.00	0.00	0.00	0.00
tons/year	0.00	0.85	0.00	0.00	0.00	0.00

Table 10.3-5
Facility Exempt Emissions (FXMT)

	NO_X	ROC	CO	SO_X	PM	PM_{10}
PTO 9101 - Platform Harmony						
tons/qtr	6.46	2.55	1.34	1.92	0.42	0.42
tons/year	25.84	10.20	5.34	7.68	1.64	1.64

10.4 Equipment List

Except as described below, the permitted equipment for Platform Harmony is the same as listed in PTO 9101 that was issued on September 4, 1994.

The permit-exempt/insignificant activities list is noted as those items listed as exempt from APCD Rule 201.

- All Tables: All emission factors and operating schedules have been deleted. This will ensure that conflicts with Sections 4, 5 and 9 do not exist.

- All Tables: Exemption citations updated where applicable.

- Table D (*Compressors*): Updated per ATC and PTO 9640.

- Table F (*Pigging Equipment*): Updated per ATC 9827.

- Table L (*Fugitive Emission Components*): Updated per ATC and PTO 9640, ATC 9837 and ATC/PTO 10037.

- Table P (*Supply Boats*): Updated per ATC/PTO 10170

- Table Q (*Crew Boat*): Updated per ATC/PTO 10170

To reduce paperwork, the list of equipment subject to permit is maintained in electronic format (3 ½ - inch floppy disks). Each category of equipment is listed in a separate table. Equipment exempt pursuant to Rule 202 are specifically noted as such and are included to denote the permit-exempt/insignificant activities for the platform.

Electronic File Name		Table	Table Name
table_a.doc	----	Table A	Stationary IC Engines
table b.doc	----	Table B	External Combustion Sources
table_c1.doc	----	Table C-1	Fixed Roof Storage Tanks
table_d.doc	----	Table D	Compressors
table_e.doc	----	Table E	Pumps
table_f.doc	----	Table F	Pigging Equipment
table_g.doc	----	Table G	Pressure Vessels
table_h.doc	----	Table H	Heat Exchangers
tabel_i.doc	----	Table I	Specialty Units and Packages
table_j.doc	----	Table J	Flares and Thermal Oxidizers
table_l.doc	----	Table L	Fugitive Emission Components
table_m.doc	----	Table M	Well Heads
table_n.doc	----	Table N	Sumps and Wastewater Tanks
table_o.doc	----	Table O	Sulfur Treating Units
table_p.doc	----	Table P	Supply Boats
table_q.doc	----	Table Q	Crew Boats
table_r.doc	----	Table R	Helicopters

table_s.doc	----	Table S	Maintenance Activities
table_t.doc	----	Table T	Stack Data

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