FINAL

PERMIT TO OPERATE NO. 8092
AND
PART 70 OPERATING PERMIT NO. 8092

EXXON – SYU PROJECT
POPCO GAS PLANT

12000 CALLE REAL, GOLETA
SANTA BARBARA COUNTY, CA

<u>OPERATOR</u>

EXXONMOBIL PRODUCTION COMPANY (“EXXONMOBIL”)

<u>OWNERSHIP</u>

PACIFIC OFFSHORE PIPELINE COMPANY (“POPCO”)

SANTA BARBARA COUNTY
AIR POLLUTION CONTROL DISTRICT

JUNE 12, 2009

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ABBREVIATIONS/ACRONYMS

AP-42	USEPA's *Compilation of Emission Factors*
APCD	Santa Barbara County Air Pollution Control District
API	American Petroleum Institute
ASTM	American Society for Testing Materials
ATC	Authority to Construct
BACT	Best Available Control Technology
BARCT	Best Available Retrofit Control Technology
bpd	barrels per day (1 barrel = 42 gallons)
Btu	British thermal unit
CAM	compliance assurance monitoring
CEMS	continuous emissions monitoring
DCS	Distributed Control System
dscf	dry standard cubic foot
E100	emitters less than 100 ppmv
E500	emitters less than 500 ppmv
EQ	equipment
ESE	entire source emissions
EU	emission unit
°F	degree Fahrenheit
FID	facility identification
gal	gallon
gr	grain
HAP	hazardous air pollutant (as defined by CAAA, Section 112(b))
H_2S	hydrogen sulfide
I&M	Inspection & Maintenance
ISO	International Standards Organization
k	kilo (thousand)
l	liter
lb	pound
lbs/day	pounds per day
lbs/hr	pounds per hour
LACT	Lease Automatic Custody Transfer
LFC	Las Flores Canyon
LPG	liquid petroleum gas
LRGO	Linear relief gas oxidizer (part of ZTOF)
M	mega (million)
MACT	Maximum Achievable Control Technology
MM	million
MW	molecular weight
NAR	Nonattainment Review
NEI	net emissions increase
NGL	natural gas liquids
NG	natural gas
NH_3	ammonia
NSPS	New Source Performance Standards
NESHAP	National Emissions Standards for Hazardous Air Pollutants
NSCR	non-selective catalytic reduction
O_2	oxygen
OCS	outer continental shelf
OTP	Oil Treating Plant

PI	Process Information System
PM	particulate matter
PM_{10}	particulate matter less than 10 microns
POPCO	Pacific Offshore Pipeline Company
ppm(vd or w)	parts per million (volume dry or weight)
psia	pounds per square inch absolute
psig	pounds per square inch gauge
PRD/PSV	pressure relief device
PTO	Permit to Operate
RACT	Reasonably Available Control Technology
ROC	reactive organic compounds, same as “VOC” as used in this permit
RVP	Reid vapor pressure
scf	standard cubic foot
scfd (or scfm)	standard cubic feet per day (or per minute)
SCR	Selective Catalytic Reduction
SIP	State Implementation Plan
SGTP	Stripping Gas Treating Plant
SOV	Stabilizer Overhead Vapor
SSID	stationary source identification
STP	standard temperature (60°F) and pressure (29.92 inches of mercury)
SYU	Santa Ynez Unit
TEG	Tri-ethylene glycol
THC, TOC	total hydrocarbons, total organic compounds
TGCU	Tail Gas Cleanup Unit
tpq, TPQ	tons per quarter
tpy, TPY	tons per year
TT	Transportation Terminal
TVP	true vapor pressure
USEPA	United States Environmental Protection Agency
VE	visible emissions
VRS	vapor recovery system
WGI	Waste Gas Incinerator
w.c.	water column
ZTOF	John Zinc Company thermal oxidation flare

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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 that affect any stationary source of air pollution in Santa Barbara County. The federal requirements include regulations listed in the Code of Federal Regulations: 40 CFR Parts 50, 51, 52, 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. This is a combined permitting action that covers both the Federal Part 70 permit (*Part 70 Operating Permit No. 8092*) as well as the State Operating Permit (*Permit to Operate No. 8092*).

The County is designated an ozone attainment area for the federal ambient air quality standard and an ozone nonattainment area for state 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 initial Part 70 permit for the POPCO Gas Plant was issued September 5, 2000 in accordance with the requirements of the APCD's Part 70 operating permit program. This permit is the third renewal of the Part 70 permit, and may include additional applicable requirements. The APCD triennial permit reevaluation has been combined with this Part 70 Permit renewal, and this permit incorporates previous Part 70 revision (ATC/PTO) permits 8092 R1, ATC/PTO 11130, PTO 8092 Mod-03, PTO 11598, and PTO 11599. The POPCO Gas Plant is a part of the *Exxon - Santa Ynez Unit ("SYU") Project* stationary source (SSID = 1482), which is a major source for VOC [a], 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. Stationary Source/Facility Overview

1.2.1 Stationary Source/Facility Overview: The POPCO Gas Plant is part of the *Exxon – SYU Project* stationary source. Pacific Offshore Pipeline Company ("POPCO"), a subsidiary of Exxon Mobil Corporation, owns the facility. ExxonMobil Production Company ("ExxonMobil"), an unincorporated division of Exxon Mobil Corporation, operates the facility.

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[a] 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.

The POPCO facility processes raw sour gas produced from the ExxonMobil owned and operated Santa Ynez Unit oil and gas field located in the Outer Continental Shelf off the western Santa Barbara Channel. The Project is comprised of the following facilities:

- Platform Hondo to POPCO Gas Plant Pipeline. The sour gas produced from the ExxonMobil Santa Ynez Unit is delivered to the POPCO gas processing plant located in Las Flores Canyon, Santa Barbara County, via an underwater and onshore 12-inch diameter pipeline. The pipeline originates at ExxonMobil's OCS Platform Hondo located 5 miles offshore. The pipeline is sized to handle up to 90 MMSCFD of sour gas. Up to 80 MMSCFD can be delivered to the POPCO plant and up to 15 MMSCFD can be delivered to the ExxonMobil Las Flores Canyon gas plant for processing by ExxonMobil into fuel that is used in their facility's combustion and energy producing equipment (primarily a 49 MW gas turbine-powered electric/steam cogeneration unit).

- The POPCO Gas Plant. The POPCO facility was the first to operate in the consolidated Las Flores Canyon oil and gas processing area. POPCO began routine operations starting in July 1984. Once the raw sour gas is delivered to the POPCO Gas Plant facility via the pipeline from Platform Hondo, this gas is treated first to remove condensate (consisting of natural gas hydrocarbon liquids and water), then to remove hydrogen sulfide using regenerable amine solutions, and finally compression to natural gas transmission line pressures (approximately 1000 to 1100 psig). In addition, the plant contains a Sulfur Removal Unit ("SRU") process to convert the extracted hydrogen sulfide into elemental sulfur; the capacity of the SRU is 60 LTD of elemental sulfur. The elemental sulfur is sold and trucked out of the facility as a by-product chemical. The plant also contains ancillary processes which generate emissions, consisting of: two 41 MMBtu/hr steam boilers used primarily to supply process heat for amine regeneration and natural gas liquids processing, but also used to incinerate SRU tail gas produced from the SRU Stretford Unit which contains approximately 143 ppmvd total reduced sulfur (of which 21 ppmvd is H_2S); two tri-ethylene glycol (TEG) reboilers burning natural gas; an electrically-driven propane-refrigerant gas treatment system; and, a thermal oxidation unit (called a "ZTOF") utilized to safely handle and dispose waste hydrocarbon and SRU gases generated during facility start-ups, shutdowns, and process upsets.

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 Permitting History: POPCO has operated the existing gas processing plant since 1984.

The following is a summary of past and present ATC and PTO permits and applications for this facility:

Permit Number: ATC 4078

Final Issue Date: 7/30/1980

Summary: The scope of the ATC was a two-phase project. The first phase to be built was a 30 MMSCFD gas processing capacity facility; and the second phase to be built was to be a 60 MMSCFD processing plant. The second phase was never built consistent with the ATC permit.

Consistent with the New Source Review rule in effect on that date ATC 4078 was issued, the ATC triggered the requirement to apply BACT to the B-801 A/B NO_x emissions and BACT for the SRU SO_x emissions. An Air Quality Impact Analysis ("AQIA") and emission offsets for any project criteria pollutant were not triggered by this ATC.

With the fugitive emission calculations documented by ATC 4078, however, there is one significant aspect of the original NEI calculations that merits additional discussion. This is that POPCO's ATC 4078 application stated that an estimated quantity of 608 valves would be installed to build the Phase I facility rated at processing up to 30 MMSCFD of gas. The fugitive emissions attributed to the Phase I facility as specified and permitted under ATC 4078, were thus the 608 valves times the fugitive emission factor of that permit, for a total of 3.37 tons/year of fugitive ROC emissions (8.86 tons/year of total hydrocarbon emissions as stated in the ATC 4078 application). However, the installed valve count in the existing facility was actually 3,956 valves. The APCD has addressed this inconsistency with POPCO. The APCD contended that a correct ATC 4078 application would have identified a valve component count that should have been much closer to the 3,956 valves that were actually installed. However, in recognition of the significant time-span between the Phase I facility which was originally permitted and constructed in the early 1980's, and the fact that attention to and procedures for counting fugitive emission sources has become more sophisticated over time, the APCD has permitted, through ATC 9047, the entire existing facility's installed valve count of 3,956 valves.

Permit Number: PTO 4078

Final Issue Date: 12/16/1983

Summary: The PTO was issued with an analysis similar to that of the ATC, including emission factors and BACT analyses. POPCO initially began operations under this PTO in late December 1983. During this early operating period, the facility was found to have delivered sales gas with a higher than allowed by PUC standard hydrogen sulfide content to the main PUC gas distribution line. The facility was required by several agencies to cease operations until the source of this problem was identified and corrected. Subsequent to implementing several corrective actions, the facility began routine operations under this PTO in July 1984.

Permit Number: PTO 8092

Final Issue Date: 6/15/1990

Summary: This PTO was issued as part of the required triennial permit reevaluation process performed pursuant to the California Health and Safety Code, Section 42301(e). The primary purpose of a reevaluation is to update the existing PTO to reflect the requirements of any new rules and regulations. PTO 8092 incorporated equipment specific emission limits for each permitted and exempt emission unit associated with the existing 30 MMSCFD facility built per the original ATC 4078. The previous PTO 4078 only specified overall facility emission limits. In addition, a revised fugitive emissions limit for all the installed valves and fittings in hydrocarbon service was specified in this permit, consistent with EPA/Radian Six Gas Plant

Study (published circa 1983) derived emission factors adopted by the APCD at that date. These revised and updated fugitive emission factors form the basis of this facility's PTE emission calculations.

Permit Number:	PTO 9215
Final Issue Date:	9/27/1996

Summary: This PTO was issued as a follow-up to ATC 9215-01 and ATC 9215-02 issued by the APCD for installation of low-NO_x burners in the process boilers B-801A/B pursuant to the requirements of APCD Rule 342. The PTO documents the emission limits, control equipment, process controls, source testing and recordkeeping requirements for this equipment consistent with APCD Rule 342 and the New Source Review Rule 205.C.

Permit Number:	ATC/PTO 9471
Final Issue Date:	4/16/1991

Summary: This ATC documents the installation of a vapor recovery system for the facility's pressure drain system to comply with APCD Rule 359 - *Flares and Thermal Oxidizers*. The vapor recovery system is designed to fully recover up to 10 SCFM of sour gas released to this system back into the facility's gas processing equipment. Previous to this system's installation, these sour vapors were released to the facility's thermal oxidizer. Subsequent to June 1994, and the adoption of APCD Rule 359, such planned releases or sour gas (in excess of 239 ppmv total sulfur) were prohibited.

Permit Number:	ATC 9471-01
Final Issue Date:	3/6/1997

Summary: This permit allowed for the a tie-in to the Pressure Drain System vapor recovery system to effect the full control of pig receiver pressure blowdowns. Because of the high sulfur content of this gas, the full capture of the pig receiver blowdown eliminates 1.18 lb/hr, and 0.07 tons/year of facility SO_x emissions.

Permit Number:	ATC 9487
Final Issue Date:	4/16/1996

Summary: ATC authorizes the installation of a Flare Volume Metering System to measure the volumetric flow rate and total volumes of gas/vapor release to the facility's thermal oxidizer. The equipment specified in this ATC is required to meet the requirements of APCD Rule 359 (*Flare Minimization Plan*).

Permit Number:	ATC 9047
Final Issue Date:	2/4/1997

Summary: This ATC authorized a significant expansion of the existing facility's gas processing capacity from 30 MMSCFD to 60 MMSCFD of raw sour gas containing up to 2.67 percent hydrogen sulfide ("H_2S").

To accomplish this, the facility was modified to: 1) add new pressure vessels to debottleneck certain existing gas processing equipment; 2) add additional components which emit fugitive hydrocarbon emissions; 3) significantly modify the existing Sulfur Removal Unit ("SRU") to debottleneck its acid gas processing capacity and authorize an increase from it of permitted oxides of sulfur (SO_x) mass emissions; and 4) restrict peak hourly and daily volumes of gas sent to the existing facility's John Zink Thermal Oxidation Flare (or "ZTOF") during planned activities such as equipment maintenance and facility startup.

In addition: The Project resulted in a reduction of fugitive hydrocarbon emissions as compared to the prior facility's permitted emissions. This occurred as a result of POPCO retrofitting existing facility fugitive emitting valves and fittings with Best Available Retrofit Control ("BARCT") technology, and implementation of Best Available Control Technology ("BACT") into any new fugitive emitting component; The Project implemented BACT for the control of SO_x emissions from: A) the modified SRU unit and its increased capacity; B) potential SRU failures and flaring of acid gas; and C) processes which combust natural gas fuel; The modified project description and operational restrictions specified in the permit that apply to planned uses of the ZTOF during equipment maintenance and facility startup activities will result in reduced hourly flaring combustion emissions, such that no violation of the ambient air quality standard for NO_2, CO, SO_x, PM_{10} and TSP will result.

Permit Number: ATC 9047-01
Final Issue Date: 2/4/1997
Summary: ATC mod application to limit hourly Startup Flaring rate. This reduced rate ensures compliance with AAQS for 1-hour NO_2 standard; the ZTOF operational restrictions applied for in the ATC 9047-01 application were directly incorporated into ATC's 9047 final decision document ("FDD"). As such, the issuance of the modified ATC 9047-01 permit was considered a part of ATC 9047.

Permit Number: ATC 9675
Final Issue Date: 2/28/1997
Summary: Installation of a Natural Gas Liquids (NGL) transfer system between the POPCO and ExxonMobil processing facilities.

Permit Number: ATC 9693
Final Issue Date: 4/4/1997
Summary: Low-NO_x burner modifications to the two Utility Boilers.

Permit Number: ATC 9047-02
Final Issue Date: 7/22/1997
Summary: This ATC authorized POPCO to install additional components in fugitive hydrocarbon service associated with the gas plant expansion permitted under ATC 9047, to incorporate some minor administrative amendments to the descriptions, evaluations and conditions contained in ATC 9047, as well as to incorporate some minor component count revisions for the NGL Interconnect Project of ATC 9675. ROC emissions increased by 9.51 lb/day and 1.74 tpy.

Permit Number: PTO 8092-02
Final Issue Date: 2/8/1999
Summary: Eliminated DAS and odor monitoring conditions from this permit. The conditions were moved to ATC 9047.

Permit Number: ATC 9047-03
Final Issue Date: 2/9/1999
Summary: This ATC modified permit conditions 37 (Ambient Air Quality and Odor Monitoring Program) and 41 (Central Data Acquisition System) and added permit condition 41.a (Data Acquisition System Operation and Maintenance Fee).

Permit Number: Trn O/O 8092-01

Final Issue Date: 4/13/1999

Summary: Application to transfer operator from POPCO to ExxonMobil Company USA.

Permit Number: ATC 9047-05

Final Issue Date: 10/22/1999

Summary: This ATC authorized the expansion of the gas plant to process an annual average inlet (raw) gas rate of 75 MMSCFD and a daily maximum of 75 MMSCFD inlet (raw) gas on any given day. Permit condition 15 (*Facility Use Limitations*) was revised.

Permit Number: ATC 9047-04

Final Issue Date: 12/22/1999

Summary: This ATC permit addressed all remaining SCDP issues from the issuance of ATC 9047. Included were: (a) an increase in the fugitive hydrocarbon component count, (b) ROC emissions from the Stretford Oxidizer Tank, (c) solvent use, (d) planned flaring and (e) vacuum truck use. In addition, the facility emission tables in Section 5 were all revised and emission offset tables in Section 7 were added.

Permit Number: PTO Part 70 8092

Final Issue Date: 9/5/2000

Summary: This permit consolidated the ATC and PTO's issued since PTO 8092 was first issued on 6/15/90. Federal Part 70 requirements were also incorporated into the permit at this time.

Permit Number: ATC/PTO Part 70 10767

Final Issue Date: 8/20/2002

Summary: This permit allows POPCO to increase the daily inlet sour gas throughput from 75 MMSCFD to a maximum of 80 MMSCFD for gas containing a maximum of 7,000 ppmv H_2S. This permit did not allow an increase in POPCO's potential to emit; the rate increase was accomplished within the emission limits specified in POPCO's previous established in PTO/Pt 70 8092, issued September 5, 2000.

Permit Number: ATC/PTO Part 70 10932

Final Issue Date: 12/27/2002

Summary: This permit allows POPCO to inject steam into the flame zone of Utility Boiler B-801A to comply with the emission limits of Part 70/PTO 8092. Injection of 50 psig steam shall be limited to no more than 650 lb/hr, as verified by an equivalent steam delivery pressure to the Utility Boiler burner steam injection wand of no more than 10 psig. POPCO shall implement the APCD-approved Steam Injection Operating and Monitoring Plan for the life of the project. This permit does not allow an increase in POPCO's potential to emit.

Permit Number: ATC/PTO Part 70 11001

Final Issue Date: 5/19/2003

Summary: This permit allowed ExxonMobil to decrease their stationary source de minimis ROC emissions total by adding a portion to the stationary source NEI ROC total. The additional ROC NEI was offset by four ERC's generated due to various facility shutdowns.

Permit Number: ATC/PTO Part 70 11130

Final Issue Date: 4/2/2004

Summary: This permit reduces the fugitive hydrocarbon leak threshold for valves and flanges/connections in gas/vapor service to 100 ppmv. Four hundred thirty four (434) standard valves – subject to BARCT will be reclassified as "Category C" valves, and one thousand three hundred two (1,302) standard flanges/connections will be reclassified as "Category C" flanges/connections.

Permit Number: PTO Part 70 8092-03

Final Issue Date: 7/30/2004

Summary: This permit changes the monitoring requirement from wastewater sampling to ROC emissions source testing for ongoing justification of the Rule 325.B.3 exemption for wastewater tanks T-807 and T-601. It also defers the demonstration of the Rule 325 exemption (via source test) for tank T-807 until the tank is put back in service.

Permit Number: DOI 0034

Final Issue Date: 10/13/2004

Summary: This ERC application is for the creation of ROC ERCs by decreasing the minor leak detection threshold to 100 ppmv for 919 valves and 2,757 flange/connection components in hydrocarbon service at the POPCO and Las Flores Canyon facilities.

Permit Number: PTO 11598

Final Issue Date: 10/17/2005

Summary: This permit was issued due to the March 17, 2005 revision to APCD Rule 202 {*Exemptions to Rule 201*} that resulted in the removal of the compression-ignited engine (e.g., diesel) permit exemption for units rated over 50 brake horsepower (bhp). That exemption was removed to allow the APCD to implement the State's Airborne Toxic Control Measure for Stationary Compression Ignition Engines (DICE ATCM). This permit covers in-use firewater pumps, with annual maintenance and testing operation limited by NFPA 25.

Permit Number: PTO 11599

Final Issue Date: 9/22/2005

Summary: This permit was issued due to the March 17, 2005 revision to APCD Rule 202 {*Exemptions to Rule 201*} that resulted in the removal of the compression-ignited engine (e.g., diesel) permit exemption for units rated over 50 brake horsepower (bhp). That exemption was removed to allow the APCD to implement the State's Airborne Toxic Control Measure for Stationary Compression Ignition Engines (DICE ATCM). This permit covers In-Use emergency standby (E/S) generators with annual maintenance and testing operation limited to 20 hours or less.

Permit Number: ATC/PTO 12020

Final Issue Date: 8/15/2006

Summary: This permit was issued to divert reaction furnace combustion gases from the boiler to the thermal oxidizer during cold startups. Unplanned flaring was added to permitted emissions.

Permit Number: PTO 12680

Final Issue Date: 9/25/2008

Summary: This permit was issued for an existing 2.1 MMBtu/hr process heater which became subject to permit due to the 1/17/2008 revision to Rule 202. This permit enforces the requirements of Rule 361.

1.3. *Emission Sources*

The emissions from the POPCO Gas Plant come from two utility boilers, a sulfur plant, fugitive components, one methanol storage tank, two wastewater storage tanks, a thermal oxidizer, four IC engines, and solvent use. Section 4 of this permit provides the APCD's engineering analyses of these emission sources. Section 5 of this permit describes the allowable emissions from each permitted emissions unit and also lists the potential emissions from non-permitted emission units.

1.4. *Emission Control Overview*

Air pollution emission controls are utilized at the POPCO Gas Plant. The emission controls employed at the facility include:

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

- Implementation of BACT and BARCT levels of control for fugitive hydrocarbon emissions from piping components as required by ATC 9047.

- Use of low-NO_x burners on the two utility boilers.

- Use of a thermal oxidizer for the combustion of waste gases.

- Use of low sulfur plant natural gas as fuel gas for the utility boilers.

- Use of two sulfur recovery processes; first a "Claus" type process, and further H_2S reduction by processing the Claus effluent gases through a Beavon and Stretford Tail Gas Unit.

- Use of a vapor recovery systems to collect hydrocarbon vapors from various tanks and vessels.

- Use of carbon canisters on wastewater tank vents to eliminate odors.

- An Enhanced Inspection & Maintenance program for detecting and repairing leaks of hydrocarbons from standard valves and flanges/connection at a lower threshold of 100 ppmv to create emission reduction credits.

1.5. *Offsets/Emission Reduction Credit Overview*

1.5.1 Offsets: NEI emissions from the POPCO Gas Plant must be offset pursuant to the APCD’s New Source Review regulation. Offsets are required for ROC, NO_x, SO_x, PM and PM_{10}. Section 7 details the offset requirements for the facility. NEI emissions do not equal the permitted emissions for this facility.

1.5.2 ERCs: Per DOI 0034 POPCO generated 0.263 TPQ ROC (1.052 TPY) due to implementation of an enhanced fugitive inspection and maintenance program as permitted under ATC/PTO 11130.

1.6. Part 70 Operating Permit Overview

1.6.1 Federally-enforceable Requirements: All federally enforceable requirements are listed in 40 CFR Part 70.2 (*Definitions*) under "applicable requirements." These include all SIP-approved APCD Rules, all conditions in the APCD-issued Authority to Construct permits and all conditions applicable to major sources under federally promulgated rules and regulations. All permits (and conditions therein) issued pursuant to the OCS Air Regulation are federally enforceable. All these requirements are enforceable by the public under CAAA. (*see Section 3 for a list of the federally enforceable requirements)*

1.6.2 Insignificant Emissions Units: Insignificant emission units are defined under APCD Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. Insignificant activities must be listed in the Part 70 application with supporting calculations. Applicable requirements may apply to insignificant units. See Attachment 10.3 for a list of Part 70 insignificant units.

1.6.3 Federal Potential to Emit: The federal potential to emit ("PTE") of a stationary source does not include fugitive emissions of any pollutant, unless the source is: (1) subject to a federal NSPS/NESHAP requirement, or (2) included in the 29-category source list specified in 40 CFR 51.166 or 52.21. The federal PTE does include all emissions from any insignificant emissions units. (*See Section 5.4 for the federal PTE for this source)*

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

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. POPCO made no request for permitted alternative operating scenarios.

1.6.6 Compliance Certification: Part 70 permit holders must certify compliance with all applicable federally enforceable requirements including permit conditions. Such certification must accompany each Part 70 permit application; and, be re-submitted annually on or before March 1st or on a more frequent schedule specified in the permit. A "responsible official" of the owner/operator company whose name and address is listed prominently in the Part 70 permit signs each certification. (*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 4.11.3, CAM).*

1.6.8 Hazardous Air Pollutants ("HAPs"): 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. (*see Sections 4.14 and 5.5)*.

1.6.9 Responsible Official: The designated responsible official and their mailing addresses are:

Mr. Frank C. Betts (SYU Operations Superintendent)
ExxonMobil Production Company
(a division of Exxon Mobil Corporation)
12000 Calle Real
Goleta, CA 93117

Telephone: (805) 961-4078

and

Mr. James D. Siefried (Operations Manager)
ExxonMobil Production Company
(a division of Exxon Mobil Corporation)
396 West Greens Road
Houston, TX 77067
Telephone: (713) 431-2047

Figure 1.1 Location Map Santa Ynez Unit Project - Onshore

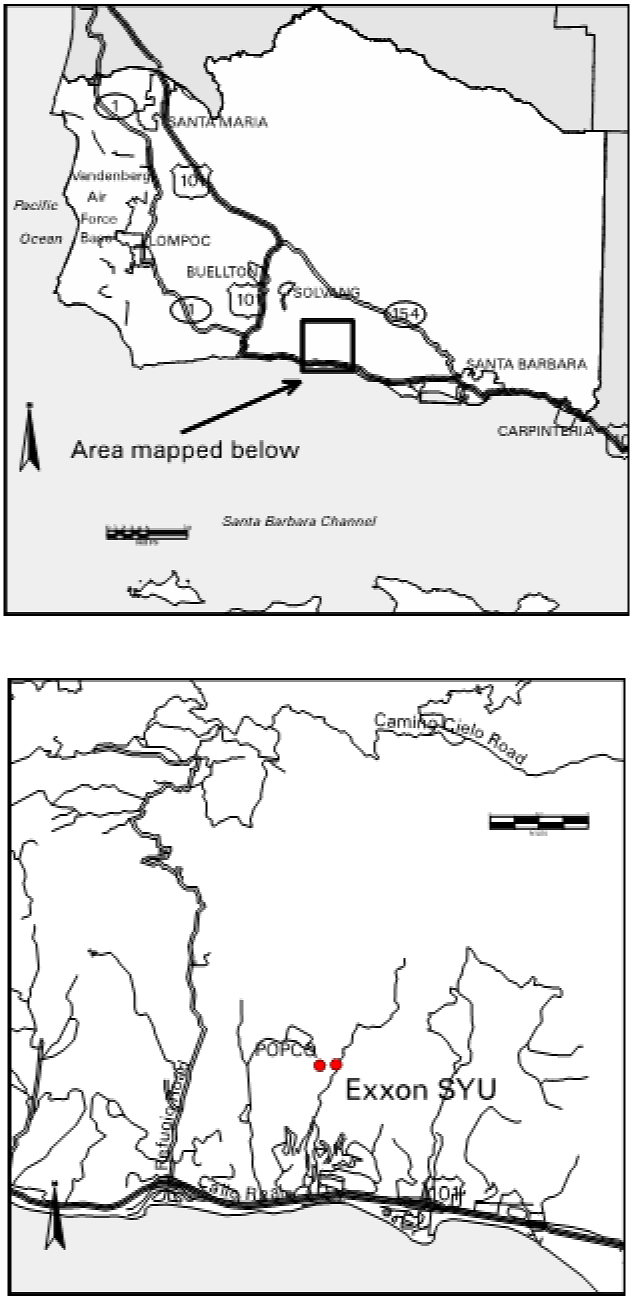
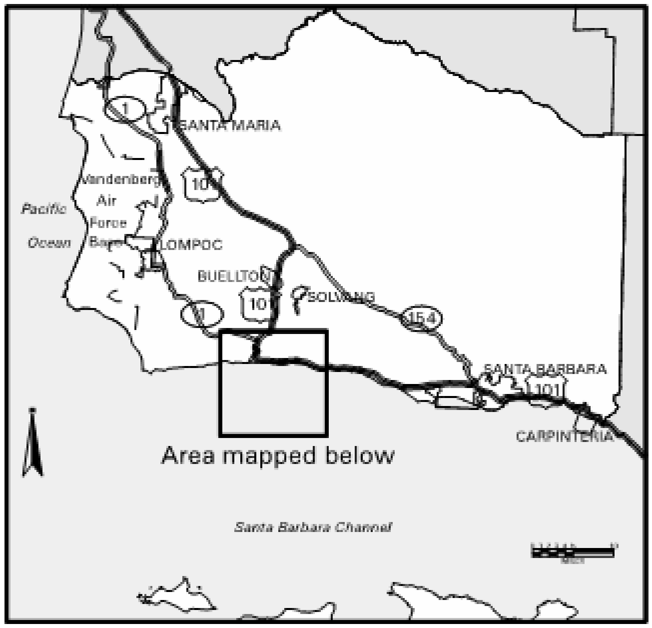
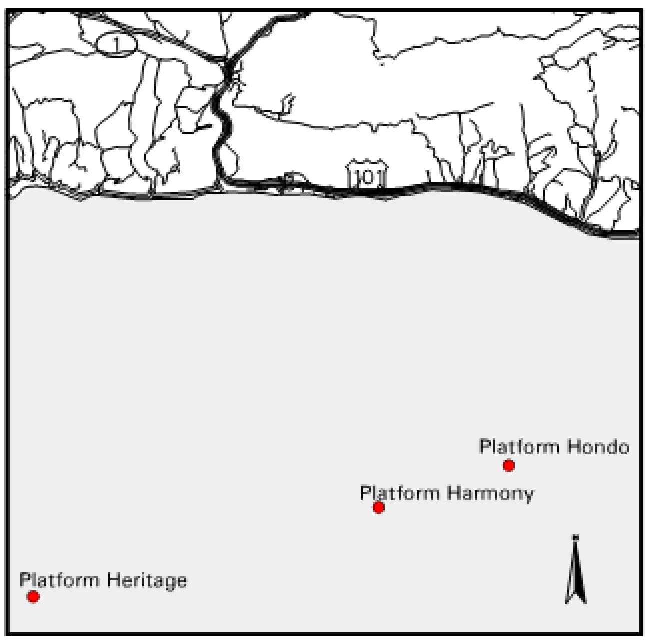


Figure 1.2 Location Map Santa Ynez Unit Project - Offshore





2.0 Description of Proposed Project and Process Description

2.1. Project and Process Description

2.1.1 Project Ownership: Pacific Offshore Pipeline Company ("POPCO"), an unincorporated division of Exxon Mobil Corporation, owns the Gas Plant. ExxonMobil Production Company ("ExxonMobil"), an unincorporated division of Exxon Mobil Corporation, operates the Gas Plant. ExxonMobil is the major owner and operator of the remaining Santa Ynez Unit facilities, including OCS Platforms Hondo, Harmony and Heritage.

2.1.2 Geographic Location: The onshore facilities are located in Las Flores Canyon ("LFC") approximately 20 miles west of Santa Barbara, California in the southwestern part of Santa Barbara County. The property consists of a pie-shaped piece of property, approximately 1500 acres, starting on the north side of Highway 101 and continuing to the north. Of this area, approximately 110 acres have been cleared with 34 acres containing facilities and the remainder left as open space. A paved road about 1.5 miles long from Calle Real, the frontage road off Highway 101, provides access to the facility.

Within the property, approximately 17 acres is leased to POPCO to operate a natural gas treating facility. Small areas of the property provide space for utility connections by Southern California Gas Company, Southern California Edison Company as well as a pump station by the All American Pipeline Company for crude transportation. The remaining part of the property is used to operate ExxonMobil's LFC oil and gas plant.

The property is located within the western part of the Transverse Ranges physiographic province of Southern California. This region is characterized by predominately east west oriented topographic and structural elements. The canyons area is predominately rural in character, with some agricultural and industrial uses present.

2.1.3 Facility Description: The SYU Project develops production from three platforms (Platforms Hondo, Harmony and Heritage) located offshore California in the Santa Barbara Channel. The production is transported to shore through a subsea pipeline and treated in production facilities located in Las Flores Canyon. The POPCO Gas Plant processes the majority of the natural gas produced by the SYU Project. Overall recovery from the development totals approximately 500 million barrels of crude oil and almost one trillion cubic feet of natural gas.

The POPCO Gas Plant receives the raw natural gas from the offshore platforms via the 12-inch produced gas pipeline. The Gas Plant produces PUC quality natural gas, propane, butane and sulfur products for sale. The recovered produced water is treated to acceptable standards and returned to Platform Harmony for release to the ocean in accordance with NPDES permit No. CA0110842.

2.1.4 Gas Dehydration, Sweetening and Fractionating: The gas plant is designed to process a total of 80 MMSCFD of sour gas from the pipeline, and if the sour gas approaches the design limit of 2.67 percent hydrogen sulfide content only 60 MMSCFD of gas can be processed. The lower gas processing throughput limit as a function of higher hydrogen sulfide content is due to SRU throughput limitations. The gas plant separates the hydrogen sulfide (H_2S), propane, butane, and heavier hydrocarbons (C_5+) from the sour gas. The treated natural gas, comprised primarily of methane and ethane, is then sold to the public utility company (Southern California Gas Company). The H_2S is converted to elemental liquid sulfur and is trucked offsite. Propane, butane and heavier hydrocarbons are fractionated from the gas condensate in the plant's Stabilizer tower, and sent to NGL storage vessels. The Stabilizer overhead gases are further processed in the plant's gas processing system to become sales gas.

2.1.5 Sales Gas Shipping: Sales gas is sold directly to the Southern California Gas Company through a local Odorant and Metering station, where it is metered, odorized and the pressure is regulated.

2.1.6 Natural Gas Liquids Storage and Shipping: Natural gas liquids ("NGL") are produced from fractionation of the gas condensates that are collected in the plant gas processing equipment, in the facility Stabilizer tower. The NGL is comprised of propane and heavier molecular weight hydrocarbons. NGL is stored in three pressurized "bullet" tanks.

Most of the NGL is sent via a pipeline to the adjacent ExxonMobil facility for further fractionation into propane, butane, and a residual natural gas liquid intermediate product. Some of the propane product (some butane also) will be trucked offsite from the ExxonMobil facilities. The NGL and butane fractions will be blended back into Exxon's treated crude to the maximum extent feasible consistent with that project's county land use permit requirements.

2.1.7 Sulfur Recovery Unit: Acid gas from the amine unit is processed in the SRU in three stages. The first stage is a "Claus" reaction process, where H_2S is catalytically converted to elemental sulfur. The elemental sulfur from this part of the SRU is trucked out of the facility for use as a fertilizer and other industrial and commercial uses.

The second stage is a "Beavon" unit, where the Claus tailgas residual SO_2 content is converted back into H_2S. This is done with a catalytically induced hydrogenation reaction process.

The third stage of the SRU is processing of the H_2S enriched Beavon tailgas through a Stretford process. The Stretford process utilizes an aqueous-based vanadium catalyzed oxidation-reduction system to selectively absorb H_2S from the Beavon tailgas in a two-stage contactor system. The H_2S, once absorbed, is converted to elemental sulfur. This sulfur is skimmed from the Stretford solution and sent to a filter press to remove residual Stretford solution prior to truck shipment from the plant as a hazardous waste product (State of California designation). The Stretford solution is both skimmed of sulfur in the oxidizer tanks and is also regenerated in these tanks. Regenerated Stretford solution is then recycled back into the contactors to remove additional H_2S from the Beavon tailgas.

In 1997, SRU modifications included a new burner system, incorporation of a pure oxygen feed system, and other process controls to accept up to 60 LTD of H_2S for processing (up from the prior 30 LTD capability). The additional SRU throughput capability is gained through substituting pure oxygen for ambient air to combust the SRU acid gas feed. The use of pure oxygen (delivered from the LOX storage tank and vaporizer system) in effect backs out the inert nitrogen that is passed through the SRU when ambient air is used. Removing nitrogen, thus allowed the existing SRU to be hydraulically de-bottlenecked to handle the anticipated additional acid gas flows generated by the 60 to 80 MMSCFD of sour gas processing capacity.

This process employs what is considered Best Available Control Technology that is designed to remove at least 99.9 percent of the mass H_2S from the acid gas, or reduce the residual H_2S

concentration in the SRU tailgas exiting the final Stretford Tailgas Unit treatment process to no more than 100 ppmv (dry basis), whichever is the more stringent requirement. The SRU process, however, is not nearly so effective at removing other reduced sulfur species such as mercaptans, carbon disulfide, and carbonyl sulfide either entering in the acid gas feed, or generated as a byproduct through the processing of the SRU inlet acid gas. These other reduced sulfur compounds also contribute to this processes total SO_x emissions. Two additional performance standards control the total SO_x emissions emitted by the SRU process; these standards are the 40 CFR, Subpart LLL requirements, and the total SO_x mass emissions cap of the process. POPCO has proposed a total sulfur reduction efficiency performance of this process which at and below 20 LTD achieves 98.0 %, and above 20 to 60 LTD achieves 99.9% total sulfur reduction, as well as no more than 5.44 lb/hr of SO_2 emissions from incineration of the SRU tailgas in the Utility Boilers.

2.1.8 Waste Gas and Emergency Flaring: The gas plant is equipped with closed vent systems (hydrocarbon and acid gas manifolds) to collect all planned and unplanned releases of vented gases for incineration in the flare system (ZTOF & LRGO). Venting of process gases to the flare is expected due to routine planned equipment commissioning and purging of vessels for maintenance. In addition, unplanned, emergency equipment failures and other process upsets may also vent gases to the LRGO equipment.

In ATC 9047, two significant ZTOF/LRGO operating scenarios were evaluated pursuant to Air Quality Impact Analyses ("AQIAs"). One scenario was the impact associated with an "uncontrolled" emergency shutdown failure of the modified SRU. This uncontrolled event has the potential to generate a localized exceedance of the state and federal primary ambient air quality standards for SO_2. Pursuant to that ATC and land-use permit condition E-5, POPCO identified a SRU failure mitigation system that eliminates excess flaring associated with SRU failures, and thus prevents the air quality standard violation, if operated consistent with the conditions of this permit.

The other flaring scenario evaluated by an AQIA was facility startup flaring. This AQIA indicated that to prevent localized exceedance of the NO_2 primary standard (1 hour), the startup flaring rate as previously permitted in PTO 8092 must be reduced by 50 percent. Pursuant to a modified ATC 9047-01 application submitted by POPCO, a 50 percent reduced planned hourly flaring rate was specified, with a duration increase from 12 to 24 hours as a new limit pursuant to the conditions of ATC 9047. No ZTOF or plant equipment modifications were required to comply with these revised planned flaring limits; these limits represent reduced hourly capacity utilization of the ZTOF.

Refer to the AQIA discussion section of ATC 9047 for a more detailed discussion of these two AQIAs.

2.1.9 Vapor Recovery System: There are two vapor recovery systems in this facility. One is for the NGL loading rack operations; in this system vapors from pressurized tank trucks are returned to the facility NGL tanks via a vapor balance line. As this system is comprised of valves, fittings, and hard-piping, the ROC emissions generated from this vapor recovery system components are calculated as part of the facility fugitive emissions inventory.

The other vapor recovery system is that attached to the facility Drain Systems (Pressure Drain System, TEG Drain System and Sulfinol Drain Systems) and the pig receiver. Because this system is comprised of valves, fittings, and hard-piping systems with no possible direct to atmosphere vent path, the ROC emissions generated from this vapor recovery system components are calculated as part of the facility fugitive emissions inventory.

2.1.10 Wastewater Treatment: Wastewater is generated by the existing facility's gas processing equipment. The existing system is comprised of a closed piping system, a Sour Water Stripper ("SWS"), and two (2) wastewater holding tanks (T-807 and T-601) which are used in an interchangeable manner. The Sour Water Stripper handles water produced from systems that handle sour and hydrocarbon gases. All produced water from the sour and hydrocarbon gas systems is first sent to the SWS, where the water is heated to drive off most of any dissolved hydrocarbons and sulfides (primarily H_2S). The gases driven out of the water by the SWS are commingled with the SRU's acid gas feed stream and processed in the SRU where the H_2S is converted to elemental sulfur, and the hydrocarbons are oxidized to CO_2.

The SWS-system cleaned water is then sent either to tank T-807 or T-601. T-807 has a capacity of 8,812 gallons and usually serves as a short-term storage and flow surge system for the cleaned water from the SWS. The tank vent is equipped with a carbon adsorption device to control any residual odorous emissions from the cleaned water. After a short-term in T-807 the cleaned sour water is then usually delivered to tank T-601 prior to being pumped through a pipeline to the LFC Produced Water Treating System. T-601 has a capacity of 91,400 gallons, and it usually receives water from the SWS treatment system described above, as well as water from the boiler blowdown and boiler feed water systems. The majority of throughput into tank T-601 is from boiler blowdowns. Boiler blowdown water is non-hazardous and does not contain any appreciable hydrocarbons or sulfides, but it does have a relatively high solids content due to solids concentration from its use to make steam. The tank T-601 vent is also equipped with a carbon adsorption device to control any odors from this system.

2.1.11 Utility Boilers: The two 41 MMBtu/hr Babcock and Wilcox steam boilers (B-801A and B-801B) are fired on plant natural gas and provide process steam for the POPCO Gas Plant. The boilers are also used to combust residual Stretford off gases from the tail gas cleanup unit.

2.2. Support Systems

2.2.1 Pipeline and Pipeline Pigging Activities: The POPCO Gas Plant receives produced sour gas and water/gas condensates via a 12 inch undersea and underground pipeline from ExxonMobil's Platform Hondo. The capacity of this line is 90 MMSCFD, with up to 80 MMSCFD to POPCO and through a branch of this line, up to 15 MMSCFD to ExxonMobil's LFC oil and gas plant. The offshore-to-onshore part of the pipeline into the POPCO facility is typically pigged once or twice per day to remove condensate and water build up in the line. About once per week the pig receiver is taken out of service, and de-pressured, to remove the accumulated pigs.

Produced gas is shipped from the plant via pipeline directly to the public utility company (Southern California Gas Company). The Gas Company maintains an Odorant and Metering Station and a Pressure Limiting Station directly adjacent to the gas plant.

2.2.2 Maintenance Activities: POPCO performs a variety of maintenance activities, including welding and painting. Equipment use includes gas-powered generators, welders, forklifts and man-lifts.

2.2.3 Planned Process Turnarounds: It is anticipated that partial or complete shutdown of the gas plant for maintenance purposes may occur one or more times each year. These shutdowns are anticipated to result in some venting of gases to the flare system. Refer to Section 4 for a description of flare emission controls and Sections 5 for additional information on shutdown emissions.

2.3. Detailed Process Equipment Listing

A detailed listing of permitted and exempt equipment authorized under this permit is included in Attachment 10.3.

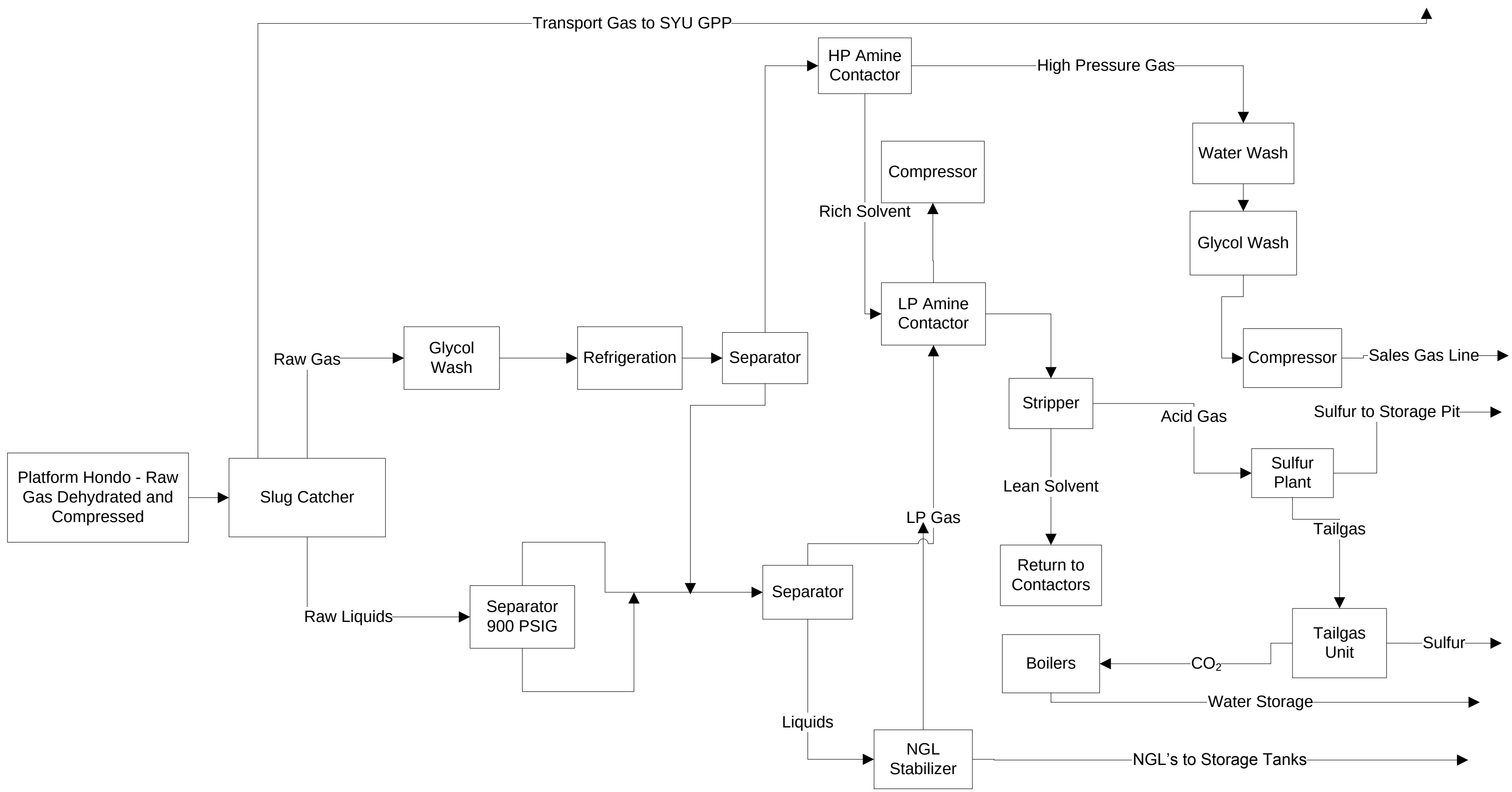


Figure 2.1 POPCO Gas Processing Plant Block Flow Diagram

3.0 Regulatory Review

3.1. Rule Exemptions Claimed

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

- As of April 2009, the *de minimis* increases (per Section D.6) are:

	ROC (lb/day)
POPCO	1.877
LFC	0.000
Platform Harmony	2.660
Platform Heritage	10.417
Platform Hondo	0.000
Entire Source:	**14.953**

- Section D.8 for routine surface coating maintenance activities.

- Section G.1.a for TEG Reboiler E-121 (process heater) fired exclusively with PUC quality natural gas (i.e., 4 ppmv H_2S and 80 ppmv total sulfur), rated at 1.2 MMBtu/hr.

- Section H.3 for all portable abrasive blasting equipment (excluding IC engines that are subject to Section F of Rule 202).

- Section L.6 for a 50,000 Btu/hr natural gas fired forced air furnace.

- Section Q.1 for a 5-gallon batch tank and associated metering pump.

- Section U.2.a for parts degreasers using unheated solvent with a surface area of less than 1 square foot.

- Section V.2 for the diesel storage tanks.

- Section V.3 for the lube oil storage tanks.

- Section V.8 for the Refrigerant make-up tank (T-151), propane 10,000-gallon capacity.

⇒ APCD Rule 311 (*Sulfur Content of Fuels*): Based on the exemption in Section A.1 for the manufacturing of sulfur or sulfur compounds, the sulfur recovery unit is exempt from the standards in this rule.

⇒ APCD Rule 321 (*Solvent Cleaning Operations*): Pursuant to Section B.2, the Safety-Kleen cold solvent degreaser is exempt from all provisions of this rule, except for Section G.2.

⇒ APCD Rule 325 (*Crude Oil Production and Separation*): POPCO claimed wastewater tanks T-601 and T-807 are exempt from the requirements of Sections D.1 and D.2 pursuant to Section B.3. T-601 was originally exempt based on the results of wastewater samples which were less than 5 milligrams ROC per liter. The results of wastewater samples completed in 2003 fluctuated above 5 milligrams per liter, and POPCO was issued a Notice to Comply (# 7843) which required a demonstration that the ROC 0.25 TPY exemption criterion applied. The test completed on November 19, 2003 met the 0.25 TPY exemption criterion for T-601. Recent tests have demonstrated T-601 no longer qualifies for the 0.25 TPY exemption. POPCO is currently determining the method by which T-601 will be retrofit to comply with the control requirements of Rule 325
POPCO does not believe that T-807 can meet the 5 milligram per liter exemption criterion and they have proposed to demonstrate ROC emissions from T-807 are less than 0.25 TPY. T-807 is currently out of service, and the permit requires ROC testing within 60-days of the date it returns to service. Failure to demonstrate T-807 is exempt would result in a violation of Rule 325, and require POPCO to comply with the control requirements in D.1 and D.2 of the Rule.

⇒ APCD Rule 326 (*Storage of Reactive Organic Compound Liquids*): Per Section B.1.b, the following emission units are exempt from all provisions of the rule:

- Compressor Lube Tanks

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

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

⇒ APCD Rule 346 (*Loading of Organic Liquids*): Per Section B.4, the transfer of liquefied natural gas, propane, butane or liquefied petroleum gases.

⇒ APCD Rule 359 (*Flares and Thermal Oxidizers*): Per Section B.2, the acid gas flare header is exempt from all requirements, except Section D.2.

⇒ APCD Rule 361 (*Small Boilers, Steam Generators, and Process Heaters*): Per Section B.1.c, the provisions of this rule do not apply to the 2.1 MMBtu/hr TEG Reboiler until March 15, 2016.

3.2. Compliance with Applicable Federal Rules and Regulations

3.2.1 <u>40 CFR Parts 51/52{*New Source Review (Nonattainment Area Review and Prevention of Significant Deterioration*)}</u>: The POPCO Gas Plant was permitted in 1980 under APCD Rule 205. The facility was subsequently modified in 1997 under APCD Rule 205.C. That rule was superseded by APCD Regulation VIII (*New Source Review*) in April of 1997. Compliance with PTO 8092 requirements and Regulation VIII ensures that the POPCO facility will comply with the federal NSR requirements.

3.2.2 <u>40 CFR Part 60 {*New Source Performance Standards*}</u>: The following NSPS apply at the POPCO facility:

- Subpart A - General Provisions
- Subpart KKK - Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants
- Subpart LLL - Standards of Performance for Onshore Natural Gas Processing; SO_2 Emissions

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

3.2.4 <u>40 CFR Part 63 Maximum Achievable Control Technology (MACT) Standards</u>:

3.2.4.1 *40 CFR Part 63 Maximum Achievable Control Technology (MACT) Standards Subpart HH* - On June 17, 1999, EPA promulgated a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage (Subpart HH). POPCO submitted an *Initial Notification of Applicability* by June 17, 1999. Based on that submittal and several subsequent letters from POPCO (2/15/02 and 5/14/02), the APCD determined that the following equipment is subject to Subpart HH:

1. The Sulfinol Glycol Regeneration System
2. The NGL storage vessels (40 CFR 63.776 (b) (2)).

The APCD concurs with POPCO's claim (Ref. APCD's 8/13/2002 letter to ExxonMobil and ExxonMobil's 8/27/2002 letter to APCD) that the GPU glycol regeneration system qualifies for exemption from MACT requirements under 40 CFR 63.764 (e) (ii) based on modeling demonstrating compliance with the 0.90 Mg/yr threshold for benzene emissions.

The APCD determined that the pressure storage vessels located at POPCO do not qualify as closed-vent systems per the definition in MACT. Therefore, section 63.773 Inspection and Monitoring requirements do not apply to these units. General MACT requirements applicable to this facility are contained in Condition 9.B.18.

The Ancillary Equipment and Compressors are exempt since POPCO implements a subpart KKK plan (40 CFR 60 subpart KKK), and had certified compliance with this plan.

3.2.4.2 *40 CFR Part 63 Maximum Achievable Control Technology (MACT) Standards Subpart EEEE* - On August 25, 2003, EPA promulgated a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Organic Liquid Distribution (Non-Gasoline) Activities (Subpart EEEE). This MACT does not apply to oil and natural gas facilities as defined in 40 CFR 63.2334(c)(1).

3.2.4.3 *40 CFR Part 63 Maximum Achievable Control Technology (MACT) Standards Subpart DDDDD* - On February 26, 2004, EPA promulgated a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Industrial, Commercial, and Institutional Boilers and Process Heaters (Subpart DDDDD). The boilers at POPCO are subject to this MACT, but were only required to complete the initial notification for "large gaseous fuel units", which was submitted on March 10, 2005.

3.2.5 40 CFR Part 64 {*Compliance Assurance Monitoring*}: This rule became effective on April 22, 1998. The following units at POPCO were either not subject to CAM or were found exempt from CAM requirements based on the section of the CAM defined in the table below:

APCD DeviceNo	Device Name	CAM Criteria not Met	CAM Exemption Claimed
2350	Boiler: B-801A	64.2.a.2	
2351	Boiler: B-801B	64.2.a.2	
2352	Sulfinol Teg Reboiler (B-251)	64.2.a.3	
2353	GPU Teg Reboiler (B-121)	64.2.a.3	
105204	Stretford Tailgas Incinerator		64.2.b.1.vi
7065	Thermal Oxidizer (ZTOF)		64.2.b.1.vi

3.2.6 40 CFR Part 68 {*Chemical Accident Prevention Provisions*}. POPCO is required to comply with the requirements of this regulation. Their initial Section 112r Risk Management Plan ("RMP") was submitted to the EPA in June of 1999. The annual compliance certification must include a statement regarding compliance with this part, including the registration and submission of the RMP.

3.2.7 40 CFR Part 70 {*Operating Permits*}: This Subpart is applicable to the POPCO facility. Table 3.1 lists the federally enforceable APCD promulgated rules that are "generic" and apply to the facility. Table 3.2 lists the federally enforceable APCD promulgated rules that are "unit-specific". These tables are based on data available from the APCD's administrative files and from POPCO'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), POPCO certified compliance with all existing APCD rules and permit conditions. This certification is also required of POPCO semi-annually. Issuance of this permit and compliance with all its terms and conditions will ensure that POPCO complies with the provisions of all applicable Subparts.

3.3. Compliance with Applicable State Rules and Regulations

3.3.1 Division 26. Air Resources {California Health & Safety Code}: The administrative provisions of the Health & Safety Code apply to this facility.

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

3.3.3 California Administrative Code Title 17 {Sections 93115}: These sections specify emission, operational, monitoring, and recordkeeping requirements for stationary diesel-fired compression ignition engines rated over 50 bhp. The firewater pumps and emergency generators are required to conform to these standards. Compliance will be assessed through onsite inspections. These standards are not federally enforceable onshore.

3.4. Compliance with Applicable Local Rules and Regulations

3.4.1 Applicability Tables: In addition to Tables 3.1 and 3.2, Table 3.3 lists the non-federally enforceable APCD promulgated rules that apply to the POPCO facility.

3.4.2 Rules Requiring Further Discussion: This section provides a more detailed discussion regarding the applicability and compliance of certain rules.

The following is a rule-by-rule evaluation of compliance for the POPCO facility:

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

Rule 302 - Visible Emissions: This rule prohibits the discharge from any single source any air contaminants for a period or periods aggregating more than three minutes in any one hour which is as dark or darker in shade than a reading of 1 on the Ringelmann Chart or of such opacity to obscure an observer's view to a degree equal to or greater than a reading of 1 on the Ringelmann Chart. Sources subject to this rule include: the thermal oxidizer, the utility boilers, the TEG reboilers, and all diesel-fired piston internal combustion engines, regardless of exemption status. Improperly maintained diesel engines and the thermal oxidizer have the potential to violate this rule. Compliance will be assured through Visible Emissions Monitoring per condition 9.B.2 by ExxonMobil staff and requiring all engines to be maintained according to manufacturer maintenance schedules per the APCD-approved *IC Engine Particulate Matter Operation and Maintenance Plan*.

Rule 303 - Nuisance: This rule prohibits POPCO from causing a public nuisance due to the discharge of air contaminants. There are no recent nuisance complaints that can be attributable to operation of the POPCO facility. All nuisance complaints are investigated by the APCD and follow the guidelines outlined in Policy & Procedure I.G.2 (*Compliance Investigations*). This rule is included in the SIP.

Rule 305 - Particulate Matter, Southern Zone: The POPCO facility 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 thermal oxidizer, the utility boilers, the TEG reboilers, and all diesel-fired piston internal combustion engines, regardless of exemption status. 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 per the APCD-approved *IC Engine Particulate Matter*

Operation and Maintenance Plan. Rule 359 addresses the need for the thermal oxidizer 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 0.1 gr/scf (at 12% CO_2) respectively. Sulfur emissions due to planned flaring events will comply with the SO_2 limit. Flaring of acid gas may not comply with the SO_2 limit, however, and POPCO will need to obtain breakdown and/or variance relief in such cases. 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. An odor monitoring station is located at the entrance (fenceline) to the Las Flores Canyon which includes the POPCO and Las Flores Canyon facilities. Data collected from the DAS system has demonstrated compliance with the limits of this rule.

Rule 311 - Sulfur Content of Fuels: This rule limits the sulfur content of fuels combusted at the POPCO facility to 0.5 percent (by weight) for liquids fuels and 15 gr/100 scf (calculated as H_2S) {or 239 ppmvd} for gaseous fuels. ExxonMobil uses CARB diesel fuel, which contains only 0.0015% sulfur. All fuel gas is required to have a sulfur content not exceeding 24 ppmv (as S). Further, the exempt TEG process heaters and the forced air furnace are required to use natural gas meeting PUC Quality standards in order to maintain their permit exemption. Compliance with this requirement is achieved through use of an inline H_2S analyzer, daily Draeger tube readings and fuel sampling. 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 usage of both photochemically and non- photochemically reactive organic solvents (40 lb/day and 3,000 lb/day respectively). Solvents may be used at the POPCO facility 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. POPCO is required to maintain records to ensure compliance with this rule.

Rule 318 - Vacuum Producing Devices or Systems – Southern Zone: This rule prohibits the discharge of more than 3 pounds per hour of organic materials from any vacuum producing device or system, unless the organic material emissions have been reduced by at least 90 percent. POPCO states that there are no emission units subject to this rule.

Rule 321 - Control of Degreasing Operations: This rule sets equipment and operational standards for degreasers using organic solvents. Small-unheated solvent cleaners that are less than 1 gallon in capacity or having an evaporative surface area of less than 1 square foot (aggregate cap of 10 square feet) are exempt from all rule provisions, except Section G.2. Compliance is determined via facility inspections.

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. POPCO is required to maintain records during maintenance operations to ensure compliance with this rule.

Rule 323 - Architectural Coatings: This rule sets standards for many types of architectural coatings. The primary coating standard that will apply to the platform is for Industrial Maintenance Coatings that have a limit of 340 gram ROC per liter of coating, as applied. POPCO is required to comply with the Administrative requirements under Section F for each container at the facility.

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

APCD Rule 325 (Crude Oil Production and Separation): This rule, adopted January 25, 1994, applies to equipment used in the production, gathering, storage, processing and separation of crude oil and gas prior to custody transfer. The primary requirements of this rule are contained in Sections D and E. Section D requires the use of vapor recovery systems on all tanks and vessels, including wastewater tanks, oil/water separators and sumps. Section E requires that all produced gas be controlled at all times, except for wells undergoing routine maintenance. All pressure vessels are connected to gas gathering systems and all relief valves are connected to the flare relief system. POPCO has installed vapor recovery on all equipment subject to this rule, except for Tank T-601. Compliance with Section E is met by directing all produced gas to a sales compressor, injection well or to the flare relief system. POPCO is currently determining the method by which T-601 will be retrofit to comply with the control requirements of this rule. The APCD will enforce compliance through an ATC.

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. The methanol tank is subject to this rule. Compliance will be assessed via APCD inspections.

Rule 327 - Organic Liquid Cargo Tank Vessel Loading: There is no organic liquid cargo tank vessel loading operations associated with this facility.

Rule 328 - Continuous Emissions Monitoring: This rule details the applicability and standards for the use of continuous emission monitoring systems ("CEMS"). Process monitoring systems (e.g., fuel use meters) are used to track emissions. CEMS are required for the facility as outlined in Section 4.11.1 and Tables 4.9 through 4.12. A number of process variables are also continuously monitored to assess compliance with permitted mass emission limits. POPCO operates the CEMS and process monitors consistent with the APCD approved CEMS Plan.

Rule 330 - Surface Coating of Metal Parts and Products: This rule sets standards for many types of coatings applied to metal parts and products. In addition to the ROC standards, this rule sets operating standards for application of the coatings, labeling and recordkeeping. This rule only applies to metal parts and products that are not currently installed as appurtenances to the existing stationary structures. It is not anticipated that POPCO 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 processing plants. POPCO will comply with this rule through implementation of the APCD approved I&M Plan. Ongoing compliance with the many provisions of this rule will be assessed via facility inspection by APCD personnel using an organic vapor analyzer and through analysis of operator records.

Rule 333 - Control of Emissions from Reciprocating Internal Combustion Engines: This rule applies to all engines with a rated brake horsepower of 50 or greater that are fueled by liquid or gaseous fuels. The IC engines at the facility include two emergency firewater pump engines and two emergency electrical generators that are no longer exempt from permit and are therefore, subject to APCD Rule 333. However, engines that operate less than 200 hours per year are exempt from Sections D, E, F, and G of Rule 333.

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. Utility Boilers B-801A and B-801B are subject to this rule. These boilers were retrofit with low-NO_X burners in order to comply with the rule's emission standards. Compliance is assessed through the monitoring, recordkeeping and reporting requirements listed in Section 9.C of this permit. Prior to 2002 compliance with the exhaust concentration limits of Rule 342 was based on source testing. In 2002 compliance with the NO_x and CO limits was determined based on source testing and on CEMS data. This PTO reevaluation 8092 R7 removes CEMS as a method of determining compliance with the NO_x and CO exhaust concentration limits. In lieu of CEMS, semiannual source testing will be required to demonstrate compliance with the NO_x and CO exhaust concentration limits, given the potential for emissions variability from the combustion of offgas in the boilers. The CEMS will continue to be used for ongoing compliance with NO_x and CO lb/hr limits.

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. This rule does not apply to any equipment at the POPCO facility.

Rule 344 - Petroleum Sumps Pits and Well Cellars: This rule applies to sumps, pits and well cellars at facilities where petroleum is produced, gathered, separated, processed or stored. There are no units at this facility subject to this 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. POPCO is exempt from this rule per Section B.4. Further, the vacuum trucks are exempt from the provisions of Sections D, E and F pursuant to Section B.5.

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. POPCO uses a thermal oxidizer to combust waste gases, as well as the utility boilers to incinerate Stretford Unit tailgas. The utility boilers are exempt from the provisions of this Rule pursuant to Section B.1. 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.

§ D.2 - Technology Based Standard: Requires all thermal oxidizers to be smokeless and sets pilot flame requirements. POPCO's thermal oxidizer is in compliance with the smokeless requirement as determined through APCD inspections and POPCO observations of the visible emissions using staff certified in visual emissions evaluations. POPCO has not demonstrated compliance with the flame pilot requirements, as each pilot is not continuously monitored for the presence of a flame.

§ 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 18.2 million standard cubic feet per month. POPCO has fully implemented their Flare Minimization Plan.

Rule 360 - Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers: This rule applies to any water heater, boiler, steam generator, or process heater rated from 75,000 Btu/hour to 2 MMBtu/hr. Any unit manufactured after October 17, 2003 must be certified to meet the NO_x emission limits of the rule. The 1.2 MMBtu/hr TEG reboiler is an existing unit so it is not subject to this rule. If POPCO installs a new unit it must comply with this rule.

Rule 361 - Small Boilers, Steam Generators, and Process Heaters: This rule applies to any boiler, steam generator, or process heater with a heat input rating greater than 2 MMBtu/hr and less than 5 MMBtu/hr. The 2.1 MMBtu/hr TEG Reboiler is an existing unit, which will become subject to this rule on March 15, 2016. The TEG Reboiler must comply with the emission limits by January 1, 2020, or upon modification if it is modified before that date. POPCO must demonstrate final compliance with this rule by January 1, 2020.

Rule 505 - Breakdown Conditions: This rule describes the procedures that POPCO must follow when a breakdown condition occurs to any emissions unit associated with the POPCO facility. A breakdown condition is defined as an unforeseeable failure or malfunction of (1) any air pollution control equipment or related operating equipment which causes a violation of an emission limitation or restriction prescribed in the 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.

POPCO will comply with this rule through implementation of the APCD approved *Emergency Episode Plan*.

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: POPCO has sought variance relief per Regulation V and received one Regular (R), and three Emergency (E) Variances since the last Part 70 renewal permit was issued:

10-06E: Granted 4/12/2006. Rules 206 and 359. Violation of condition 9.C.2.(b)(vi). Authorized planned flaring of gas with a sulfur concentration exceeding 239 ppmv while depressurizing the reboiler and stabilizer. The reboiler and stabilizer had to be depressurized in order to remove material that was plugging the equipment.

58-09E: Granted 3/26/09. Rule 206. Violation of conditions 9.C.1.(a) and 9.C.1.(a)(i). Authorized operation of boiler 801B with excess NO_x emissions during a cold start of the SRU.

54-09N: Granted 3/23/2009. Rules 206 and 359. Extended variance 13-09E for 90 days.

13-09E: Granted 2/26/2009. Rules 206 and 359. Violation of condition 9.C.2.(b)(iv). Authorized operation of the thermal oxidizer with H_2S concentrations in the acid gas greater than 239 ppmv while POPCO searched for the source of the H_2S leak.

3.5.2 Violations: The last facility inspections occurred during April 2, 2009. The inspector reported that the facility was in compliance with all APCD rules and permit conditions. The following violations have been documented since the last permit reevaluation:

NOV #8452: Violation of Rule 206 (PC 9.C.2). Issued 3/14/2006. Exceeded the permitted 500 kscfh HC flare throughput limit.

NOV #8566: Violation of Rule 206 (PC 9.C.1). Issued 6/14/2006. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #8567: Violation of Rule 206 (PC 9.C.1.(a)(v)). Issued 6/14/2006. Exceeded the permitted 5.55 lb/hr SO_x limit for Boiler 801A.

NOV #8723: Violation of Rule 206 (PC 9.C.2). Issued 10/12/2006. Exceeded the permitted SO_x emissions limit for the thermal oxidizer.

NOV #8724: Violation of Rule 206 (PC 9.C.2). Issued 12/08/2006. Exceeded the permitted 239 ppmv H_2S limit for the acid gas flare header.

NOV #8725: Violation of Rule 206 (PC 9.C.2). Issued 12/08/2006. Exceeded the permitted 239 ppmv H_2S limit for the acid gas flare header.

NOV #8729: Violation of Rule 206 (PC 9.C.2). Issued 12/08/2006. Failed to analyze samples of flare gas collected during flaring events by the Welker automatic flare gas sampling system.

NOV #8730: Violation of Rule 206 (PC 9.C.2). Issued 12/08/2006. Exceeded the permitted 239 ppmv H_2S limit for the hydrocarbon flare header.

NOV #8736: Violation of Rule 206 (PC 9.C.1). Issued 2/13/2007. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #8743: Violation of Rule 206 (PC 9.C.1). Issued 4/10/2007. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #8891: Violation of Rule 359. Issued 4/10/2007. Failed to maintain the thermal oxidizer pilot TE-834 at all times combustible gases were sent to the thermal oxidizer.

NOV #8893: Violation of Rule 206 (PC 9.C.12). Issued 4/10/2007. Failed to perform the required cylinder gas audit of AI-331 during the first quarter of 2007.

NOV #8905: Violation of Rule 206 (PC 9.C.1). Issued 9/5/2007. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801B.

NOV #9016: Violation of Rule 206 (PC 9.C.1). Issued 12/4/2007. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801B.

NOV #9017: Violation of Rule 206 (PC 9.C.1). Issued 12/4/2007. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801B.

NOV #9028: Violation of Rule 206 (PC 9.C.1). Issued 1/3/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801B.

NOV #9032: Violation of Rule 206 (PC 9.C.1). Issued 2/8/2008. Exceeded the permitted mass emissions limit for Boiler 801B.

NOV #9036: Violation of Rule 206 (PC 9.C.1). Issued 4/18/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9037: Violation of Rule 331. Issued 4/18/2008. Failed to maintain the hatch on T-601 closed at all times.

NOV #9092: Violation of Rule 206 (PC 9.C.1). Issued 4/18/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9103: Violation of Rule 206 (PC 9.C.1). Issued 8/26/2008. Exceeded the permitted 100 ppmvd H_2S limit of the Stretford tail gas combusted in the boilers.

NOV #9104: Violation of Rule 206 (PC 9.C.1). Issued 8/26/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9105: Violation of Rule 206 (PC 9.C.2). Issued 8/26/2008. Exceeded the permitted 2000 scfh flare pilot gas limit.

NOV #9107: Violation of Rule 206 (PC 9.C.1). Issued 12/16/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9108: Violation of Rule 206 (PC 9.C.1). Issued 12/16/2008. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9109: Violation of Rule 206 (PC 9.C.1). Issued 1/6/2009. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801A.

NOV #9368: Violation of Rule 206 (PC 9.C.1). Issued 3/18/2009. Exceeded the permitted 4.0 ppm H_2S limit for the sales and purchased fuel gas.

NOV #9373: Violation of Rule 206 (PC 9.C.1). Issued 3/18/2009. Exceeded the permitted 4.0 ppm H_2S limit for the sales and purchased fuel gas.

NOV #9380: Violation of Rule 206 (PC 9.C.2). Issued 3/24/2009. Failed to perform the weekly colorimetric tube measurement of the H_2S content of the gas in the acid gas and hydrocarbon gas flare headers.

NOV #9381: Violation of Rule 206 (PC 9.C.2). Issued 3/24/2009. Exceeded the permitted 2000 scfh flare pilot gas limit.

NOV #9382: Violation of Rule 206 (PC 9.C.1). Issued 3/24/2009. Exceeded the permitted 30 ppmv NO_x limit for Boiler 801B.

3.5.3 Significant Historical Hearing Board Actions/NOVs: There have been no significant *historical* Hearing Board actions since the initial Part 70 permit was issued.

Table 3.1 Generic Federally Enforceable APCD Rules

Generic Requirements	Affected Emission Units	Basis for Applicability	Adoption Date
RULE 101: Compliance by Existing Installations	All emission units	Emission of pollutants	June 1981
RULE 102: Definitions	All emission units	Emission of pollutants	January 15, 2009
RULE 103: Severability	All emission units	Emission of pollutants	October 23, 1978
RULE 201: Permits Required	All emission units	Emission of pollutants	April 17, 1997
RULE 202: Exemptions to Rule 201	Applicable emission units	Insignificant activities/emissions, per size/rating/function	June 19, 2008
RULE 203: Transfer	All emission units	Change of ownership	April 17, 1997
RULE 204: Applications	All emission units	Addition of new equipment of modification to existing equipment.	April 17, 1997
RULE 205: Standards for Granting Permits	All emission units	Emission of pollutants	April 17, 1997
RULE 206: Conditional Approval of Authority to Construct or Permit to Operate	All emission units	Applicability of relevant Rules	October 15, 1991
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.	April 17, 1997
RULE 212: Emission Statements	All emission units	Administrative	October 20, 1992
RULE 301: Circumvention	All emission units	Any pollutant emission	October 23, 1978
RULE 302: Visible Emissions	All emission units	Particulate matter emissions	June 1981
RULE 303: Nuisance	All emission units	Emissions that can injure, damage or offend.	October 23, 1978
RULE 305: PM Concentration – South Zone	Each PM source	Emission of PM in effluent gas	October 23, 1978
RULE 309: Specific Contaminants	All emission units	Combustion contaminants	October 23, 1978
RULE 311: Sulfur Content of Fuel	All combustion units	Use of fuel containing sulfur	October 23, 1978
RULE 317: Organic Solvents	Emission units using solvents	Solvent used in process operations.	October 23, 1978
RULE 318: Vacuum Producing Devices – Southern Zone	All systems working under vacuum	Operating pressure	October 23, 1978

Generic Requirements	**Affected Emission Units**	**Basis for Applicability**	**Adoption Date**
RULE 321: Solvent Cleaning Operations	Emission units using solvents	Solvent used in process operations.	September 18, 1997
RULE 322: Metal Surface Coating Thinner and Reducer	Emission units using solvents	Solvent used in process operations.	October 23, 1978
RULE 323: Architectural Coatings	Paints used in maintenance and surface coating activities	Application of architectural coatings.	July 18, 1996
RULE 324: Disposal and Evaporation of Solvents	Emission units using solvents	Solvent used in process operations.	October 23, 1978
RULE 353: Adhesives and Sealants	Emission units using adhesives and sealants	Adhesives and sealants use.	August 19, 1999
RULE 505: Breakdown Conditions	All emission units	Breakdowns where permit limits are exceeded or rule requirements are not complied with.	October 23, 1978
RULE 603: Emergency Episode Plans	Stationary sources with PTE greater than 100 tpy	ExxonMobil SYU Project PTE is greater than 100 tpy.	June 15, 1981
REGULATION VIII: New Source Review	All emission units	Addition of new equipment of modification to existing equipment. Applications to generate ERC Certificates.	April 17, 1997
RULE 1301: General Information	All emission units		September 18, 1997
RULE 1302: Permit Application	All emission units		November 9, 1993
RULE 1303: Permits	All emission units		November 9, 1993
RULE 1304: Issuance, Renewal, Modification and Reopening	All emission units		November 9, 1993
RULE 1305: Enforcement	All emission units		November 9, 1993

Table3.2 Unit-Specific Federally Enforceable APCD Rules

Unit-Specific Requirements	APCD DeviceNo	Basis for Applicability	Adoption Date
RULE 325: Crude Oil Production and Separation	103104, 103103, 102620	All pre-custody production and processing emission units	January 25, 1994
RULE 326: Storage of Reactive Organic Compounds	102620	Stores ROCs with vapor pressure greater than 0.5 psia	December 14, 1993
RULE 328: Continuous Emission Monitors	2350, 2351, 105162, 105183, 150204	Section C and NSPS	
RULE 331: Fugitive Emissions Inspection & Maintenance	102618	Components emit fugitive ROCs.	December 10, 1991
RULE 342: Control of Oxides of Nitrogen from Boilers, Steam Generators and Process Heaters	2350, 2351	Rated greater than 5 MMBtu/hr	April 17, 1997
RULE 359: Flares and Thermal Oxidizers	102614, 102615, 102616, 102617	Used in petroleum service	June 28, 1994
RULE 360: Emissions of Oxides of Nitrogen from Large Water Heaters and Small Boilers	2353	Rated between 75,000 and 2,000,000 Btu/hr	October 17, 2002
RULE 361: Small Boilers, Steam Generators, and Process Heaters	2352	Rated between 2 and 5 MMBtu/hr	January 17, 2008
RULE 901: New Source Performance Standards (NSPS)		Subpart A, KKK, and LLL	May 16, 1996

Table3.3 Non-Federally Enforceable APCD Rules

Requirement	Affected Emission Units	Basis for Applicability
RULE 210: Fees	All emission units	Administrative
RULE 310: Organic Sulfides	All emission units	Odorous sulfide emissions
RULES 501-504: Variance Rules	All emission units	Administrative
RULES 506-519: Variance Rules	All emission units	Administrative

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)
- Emission source testing, sampling, CEMS
- 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) were used to determine the non-methane, non-ethane fraction of THC.

4.2. Stationary Combustion Sources

4.2.1 General: The stationary combustion sources associated with the Gas Plant consist of two 41 MMBtu/hr natural gas utility boilers (B-801A/B), two triethylene glycol ("TEG") reboilers (E-121 rated at 1.2 MMBtu/hr and E-251 rated at 2.1 MMBtu), and four diesel-fired emergency IC engines (two firewater pumps each rated at 420 bhp and two emergency electrical generators rated at 268 bhp and 111 bhp, respectively). Electrical power at the POPCO Gas Plant is utility-grid supplied. During utility grid power losses, normal gas plant processing of sour gas ceases until power is restored.

Each boiler is capable of accepting Tail Gas Unit off gas ("TGU off gas") produced from the Stretford Unit part of the facility's Sulfur Recovery Unit ("SRU"). The TGU off gas contains up to 100 ppmv total reduced sulfur ("TRS") compounds (e.g., H_2S, COS, CS_2), which is incinerated in the boilers to oxidize the TRS compounds to oxides of sulfur (SO_x). The TGU off gas also contains small amounts of hydrogen and hydrocarbons, as well as inert gases such as CO_2 and N_2. The hydrogen and hydrocarbons can contribute an additional 5.62 MMBtu/hr of heat release within a boiler or be split between both boilers. Each stack is equipped with a CEM system that measures the concentration and mass emissions of NO_x and SO_x.

4.2.2 Emission Factors:

BOILERS - The emission factors for the two 41 MMBtu/hr Babcock-Wilcox utility boilers, shown in Table 5.2, are based on POPCO's permit application for the COEN QLN Low-NO_x burners in use. The NO_x emission factor is based on Rule 342 requirements (30 ppmv at 3% O_2) while the CO emission factor is based on the manufacturer guarantee of 100 ppmv at 3% O_2. The PM emission factor was derived from the PM_{10} factor by using a PM/PM_{10} ratio of 0.95. The SO_x emission factor is based on mass balance using a total sulfur content of 24 ppmv.

IC ENGINES – Emission factors for the IC engines are based on Table 3.3-1 of USEPA AP-42. The SO_x emission factor is based on mass balance. Mass emission estimates are based on the maximum allowed hours for maintenance and testing. Emissions are determined by the following equations:

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

The emission factors (EF) were chosen from USEPA AP-42 based on each engine's rating and age. Daily hours are assumed to be 2 hours per day (re: ATCM FAQ Ver 1.5 #32). The firewater pump engines identified in this permit must comply with NFPA 25. Since the NFPA 25 does not specify an upper limit on the hours to comply with the maintenance and testing requirements, in-use firewater pumps will not have a defined potential to emit restricting their operation.

TEG REBOILERS – Emission factors for the TEG reboilers are based on Tables 1.4-1 and 1.4-2 of USEPA AP-42. The SO_x emission factor is based on mass balance using PUC quality natural gas meeting the specifications of General Order – 58a.

4.2.3 Emission Controls: The emission controls for the two utility boilers include use of COEN QLN Low-NO_x burners. The burners on B-801A and B-801B are also equipped for steam injection (50 psig and up to 650 lb/hr) to reduce NO_x emissions. These controls were installed in 1996 (ATC 9215) in order to comply with the requirements of APCD Rule 342. The steam injection system has been implemented in both boilers B-801A and B-801B per APCD ATC/PTO 10932. There are no controls used for the IC engines or the TEG reboilers.

4.3. Fugitive Hydrocarbon Sources

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

4.3.2 Emission Factors: Emissions of reactive organic compounds from piping components such as valves, flanges and connections have been calculated using emission factors pursuant to APCD P&P 6100.061 (*Determination of Fugitive Hydrocarbon Emissions at Oil and Gas Facilities Through the Use of Facility Component Counts - Modified for Revised ROC Definition*) for components in gas/light liquid service. The component-leakpath was counted consistent with P&P 6100.061. This leakpath count is not the same as the "component" count required by APCD Rule 331. No oil service components are present at this facility.

The operator determined the number of emission leakpaths and APCD staff verified these data by checking a representative number of P&IDs and by site checks. Emissions are based on a total of 18,528 gas/condensate component-leakpaths and 0 oil/emulsion component-leakpaths. . The calculation methodology for the fugitive emissions is:

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

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

4.3.3 Emission Controls: A fugitive emissions control program is used to minimize potential leaks from the process components. Emission reductions are expected as a result of POPCO's implementation of the APCD approved Inspection and Maintenance ("I&M") Manual and component installation that is considered BACT and BARCT. The I&M program is designed to minimize leaks through a combination of pre- and post-leak controls. Pre-leak controls include venting of leaks from compressor seals to the vapor recovery system, use of dual mechanical seals on pumps in light liquid service, venting of pressure relief devices to the flare system, and plugging of open-ended lines (an open-ended line is a valve that has one side of the valve seat in contact with the process fluid, and is open to the atmosphere on the other). Post-leak controls consist of regular inspection of each leak source for leakage and repair of all components found leaking. Inspections are performed with an Organic Vapor Analyzer or other EPA Method 21 approved analyzer. Components are required to be repaired between 1 to 14 days, depending on the severity of the leak. POPCO's I&M program is consistent with the most stringent requirements of APCD Rule 331 and EPA New Source Performance Standards, Subpart KKK. POPCO's I&M program also includes a leak path identification system. Leak paths are physically identified in the field with a "tag" and given a unique number. An inventory of each tag is then maintained which describes the component type, service, accessibility and all associated leak paths. The leak path inventory serves as a basis for compliance with fugitive hydrocarbon emission limits. Table 4.1 summarizes the requirements for the I&M Program. Tables 4.2 and 4.3define the BACT requirements for the fugitive hydrocarbon sources.

Differing emission control efficiencies are credited to all components that are safe to monitor (as defined per Rule 331) due to the implementation of an APCD-approved Inspection and Maintenance program for leak detection and repair consistent with Rule 331 requirements (See Table 4.3-1 in Attachment A). The control efficiencies vary based on component design, monitoring frequency, and leak detection threshold. This facility operates bellows seal valves (100% control), Category B valves and flanges/connections (85% control), Category C valves and flanges/connections (87% control), Category F valves and flanges/connections (90% control), Category J valves (90% control), and 80% for the remaining safe-to-monitor components. Unsafe to monitor components are not eligible for I&M control credit. (See Permit Guideline Document 15 – *Fugitive Emissions from Valves, Fittings, Flanges, Pressure Relief Devices, Seals, and Other Components – Component-Leakpath Method* for a detailed discussion of the various categories defined for valves and flanges/connections). Ongoing compliance is determined in the field by inspection with an organic vapor analyzer and verification of operator records.

POPCO has classified a large number of components as “emitters less than 500 ppmv” (Category B) and “emitters less than 100 ppmv” (Category C). The component-leakpaths monitored at 500 ppmv or 100 ppmv are assigned a mass emission control efficiency depending on the monitoring frequency. Category B component-leakpaths are maintained at or below 500 ppmv as methane, and Category C component-leakpaths are maintained at or below 100 ppmv as methane, monitored per EPA Reference Method 21. For such Category B component-leakpaths, screening values above 500 ppmv trigger the Rule 331 repair process per the minor leak schedule. Screening values above 100 ppmv trigger the Rule 331 repair process per the minor leak schedule for Category C component-leakpaths.

BACT standards apply for Rule 331 components subject to NSR BACT provisions of that rule. Table 4.2 (*Rule 331 BACT Component Requirements*) lists the specific BACT requirements for these components.

4.4. Sulfur Recovery/Tailgas Unit

4.4.1 General: POPCO's Sulfur Recovery Unit ("SRU") is comprised of three separate stages: a Claus-type catalytic converter stage; a Beavon converter stage; and a Stretford tailgas unit stage. The Claus-type unit operates to convert the H_2S in the raw acid gas produced from the Sulfinol system regenerator (acid gas also contains CO_2, but CO_2 passes through the entire SRU as an inert species). The H_2S is converted to elemental sulfur. The Beavon converter is used to convert the residual quantities of byproduct SO_2 in the Claus off gas back into H_2S, whereby in the next stage of the SRU process, the Stretford tailgas unit, most all of the residual H_2S in the Beavon off gas is removed and converted into wet elemental sulfur.

The system used by POPCO incorporates BACT to remove H_2S from the acid gas feed to the SRU. The BACT standard that applies to this process is considered a different "class" of process than the standard that has been applied to date for "refinery-based" SRUs. Refinery-based SRUs typically do not contain much else in their acid gas except H_2S, because all the hydrocarbons and other reduced sulfur species were converted to H_2S in catalytic-desulfurization processes (for the gasoline, kerosene, and diesel products produced by refineries) upstream of their SRUs. Because gas plants used to produce utility-grade fuel gas directly from production wells, such as POPCO (and the adjacent ExxonMobil SYU gas plant), they handle acid gas streams which are much "leaner" (i.e., lower in concentration) in H_2S, and also contain significantly higher proportions of other reduced sulfur species than refinery-based SRU acid gases.

As a result, all of POPCO's three SRU stages basically operate most effectively to remove H_2S from the acid gas stream sent to the SRU from the POPCO gas processing equipment's amine-based gas sweetening system. The SRU systems are only partially effective at removing and converting other reduced sulfur species such as carbonyl sulfide, carbon disulfide, and mercaptans to the elemental sulfur product. Because of this limitation, this SRU's BACT standard is limited to specifying the minimum allowed H_2S reduction efficiency. This SRU's performance is also specified for minimum total sulfur reductions to ensure compliance with the applicable federal NSPS (40 CFR, Subpart LLL).

4.4.2 Emission Factors/Controls: Emission calculations for the SRU's H_2S and total sulfur recovery efficiency are based upon the minimum required reduction in these species across the SRU (see Table 4.5 and 4.6). The monitoring systems in place and the formulae used to track compliance with these specifications are shown in Figures 4.1 and Table 4.9.

The minimum H_2S and TRS recovery efficiency specifications will be met by limiting the maximum capacity of the SRU's contribution to the POPCO facility SO_2 emissions to no more than 5.44 lb/hr. This equates to a calculated H_2S mass reduction efficiency of 99.9484 percent at a 60 LTD feed rate to the SRU. It is important to note, though, this permit only specifies the H_2S and TRS mass reduction efficiencies to three significant figures (e.g., 99.9 percent for H_2S). This is because of the intrinsic (but allowed by CFR standards) instrument accuracy limitations used to monitor these efficiencies; for example, with both the inlet H_2S and Stretford tailgas H_2S, and even the boiler stack SO_2 CEM, all capable of accuracy to approximately ± 3.5%, no more than three significant figures of mass reduction efficiency can be specified. However, using the Stretford H_2S tailgas, and the boiler stack SO_2 CEMS mass emission monitors, ensures that at least the applicable three-significant-figure-based BACT and NSPS standards are achieved or even exceeded (on a calculated basis), and that total SO_2 mass emissions impact from the SRU is minimized.

In addition to SO_2 from the SRU, the Stretford tailgas also contains some residual combustible species such as hydrogen (H_2) and low molecular weight hydrocarbons that are carried through or generated by the SRU process. These combustible species are estimated to contribute up to 5.62 MMBtu/hr of additional heat release in the B-801A/B boilers during incineration of about 225,000 SCF/hr of off gas. The residual heating value of the Stretford tailgas has been estimated at 25.0 Btu/scf. In general then, the SRU incineration emissions can be calculated using formulae similar to standard combustion processes as follows:

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

where:

ER	=	emission rate (lb/period)
EF	=	pollutant specific emission factor (lb/MMBtu of incinerated gas)
FR	=	Stretford tailgas flow rate (SCF/period)
HVC	=	average high heating value from combustion of Stretford tailgas (Btu/scf).

Emissions from this waste stream are calculated separately from the main fuel gas emission calculations in two line items in Tables 5.3 and 5.4. The first line item addresses the non-SO_x criteria emissions and uses the same emission factors as used for the utility boilers. The second item addresses the SO_x emissions that are specific to the tailgas stream characteristics. As permitted under ATC 9047, the SO_x emission factor is 5.44 lb/hr. Also included in the second item are emissions of ROC from the Stretford Oxidizer Tanks. The POPCO proposed emission factor of 0.10 lb/hr is used. The pollutant specific emission factors and other data required for these calculations are documented in Section 5 of this permit.

4.5. Thermal Oxidizer

4.5.1 General: Emissions associated with a variety of flaring events are anticipated from the POPCO facility. Flaring emissions associated with the controlled start-up and shut-down of the Gas Plant for maintenance and inspection were supplied by the applicant as part of the Rule 359 *Flare Minimization Plan* activities and the POPCO *1983 Flaring Analysis*. Anticipated failure rate frequencies and emissions levels were projected in the project SEIR based on past operating records from similar facilities.

The POPCO flare relief system consists of hydrocarbon and low-pressure acid gas headers. Each of these headers connects the various PRDs and manual pressure relief/vent paths to a common enclosed ground flare (the ZTOF). No hydrocarbon service pressure relief devices are equipped with relief valves vented directly to the atmosphere. The flare itself is manufactured by John Zink and is rated at about 72,159 lbs of hydrocarbons an hour for the three ZTOF stages, and an additional 269,000 lb/hr for the LRGO stage.

4.5.2 Operating Modes: This permit categorizes all flaring activities into one of the following four categories:

- *Purge and Pilot* - Up to 2000 scfh of plant gas and 200 scfh of sales gas (PUC quality) are used to maintain pilot flames and to purge the thermal oxidizer respectively. Per APCD P&P 6100.004, this category is included in all emission scenarios (i.e., hourly, daily, quarterly and annual).

- *Planned Continuous* - This category includes all continuous flaring events. This includes compressor seal leakage to the acid gas header and "baseline" system leakage to both the hydrocarbon and acid gas headers. Each compressor is equipped with a totalizing flow meter. The baseline system leakage is a calculated value for each flare header based on the principle of taking the total volume metered at each flare header and subtracting out all known metered volumes (e.g., purge gas, compressor seal leakage, flaring events).

  The compressor seal leakage rate of 311 scfh is greater than one-half the minimum detection limit of the acid gas flare header flow meter (245 scfh) and as such an additional emissions line item is not required. Further, since the hydrocarbon flare header flow meter minimum detection limit is very low (45 scfh), it is assumed that the purge gas flow rate through the hydrocarbon flare header is greater than one-half the minimum detection limit of the flow meter (22.5 scfh), and as such an additional emissions line item is not required. Per APCD P&P 6100.004, this category is included in all emission scenarios.

- *Planned Other* - This category includes planned infrequent flaring events and is only comprised of plant startups and shutdowns, plant startups after unplanned shutdowns, maintenance, and incineration of treated tail gas during events such as boiler startups and shutdowns. Other planned flaring events may only occur via a variance per Regulation V. This category includes operations occurring a maximum of four times per year. Per APCD P&P 6100.004, emissions from this category are included only in the quarterly and annual emission scenarios. POPCO may incinerate tail gas in the thermal oxidizer for reasons other that those cited here, as long as the operational limitations defined in Table 5.1 are met.

- *Unplanned Other* - This category includes unplanned flaring that occurs unexpectedly, which is not a part of the normal operation of the thermal oxidizer. Past causes for unplanned flaring at POPCO include maintenance, pressure control valve relief, pressure safety valve relief, compressor shutdowns and startups, or plant shutdowns. In addition, POPCO is limited to a single failure of the Sulfur Recovery Unit (SRU) as defined in condition 9.C.2. Other unplanned flaring events not meeting the limits specified in condition 9.C.2 and Table 5.1 may only occur via a variance per Regulation V. Per APCD P&P 6100.004, emissions from this category are included only in the quarterly and annual emission scenarios.

4.5.3 Emission Factors: The emission factors are based on prior permitting actions. The basis for selection of the emission factors is not known. The SO_x emission factor is determined using the equation: (0.169)(ppmv S)/(HHV) [b]. The calculation methodology for the flare emissions is:

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

where:

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

To meet the requirements of Rule 359, POPCO uses purge and pilot gas that complies with the rule limit of 239 ppmv. POPCO's fuel gas for the pilot cannot exceed a total sulfur content of

[b] Reference: *SOx Emission Factors for Gaseous Fuels*, SBCAPCD, January 31, 1997

24 ppmv and the fuel gas for the purge cannot exceed a total sulfur content of 80 ppmv and a hydrogen sulfide content of 4 ppmv. With the exception of the SRU Failure, POPCO has requested a limit of 239 ppmv for unplanned other flaring.

4.5.4 Meters: The Flare Volume Metering system is divided into three parts: (1) a hydrocarbon metering system; (2) an acid gas metering system, and (3) a TO pilot fuel gas metering system.

HYDROCARBON METERING SYSTEM - The "hydrocarbon" metering system is comprised of three overlapping stages of flow metering, such that the low and very high flows in this manifold can be accurately measured. The minimum detectable flow measured by this system is 45 scfh. A "zero" reading from this metering system is assumed to be a flow of one-half the minimum detectable flow (i.e., 22.5 scfh). Specifically:

Low Flow Metering System: Installed into 3-inch flare first stage piping downstream of HC Flare K.O. Drum, V-802. Measures flow as low as 45 scf/hr and up to 0.036 MMSCF/hr. Make: Fluid Components International ("FCI"); Model No: GF90; this meter's flow readings are inherently pressure and temperature compensated.

Intermediate Flow Metering System: Installed into 16-inch flare main header piping upstream of HC Flare K.O. Drum, V-802. Measures flow rates as low as 1,125 scf/hr up to 1.14 MMSCF/hr (equivalent to 27.5 MMSCF/day). Make: Fluid Components International ("FCI"); Model No: GF90; this meter's flow readings are inherently pressure and temperature compensated.

High Flow Metering System: Installed into 16-inch flare main header piping upstream of HC Flare K.O. Drum, V-802. Measures flow rates as low as 0.729 MMSCF/hr up to 9.58 MMSCF/hr (equivalent to 17.5 to 230 MMSCF/day). Make: Dietrich Standard; Model No: Diamond II annubar; this meter's flow readings are temperature and pressure compensated.

Temperature and Pressure Transducers: As shown on POPCO P&ID No. D-972-28K, Rev. 11 (1/11/96) labeled as PT/PI #898; and TT/TI #898 for pressure and temperature respectively. These transducers are used to correct hydrocarbon flare flows measured by the annubar high flow meter system.

ACID GAS METERING SYSTEM - The other part of the system measures acid gas releases from the facility Sulfur Removal Unit ("SRU") process into the "Acid Gas" manifold; it is comprised of one "thermal dispersion" type flow meter. The minimum detectable flow measured by this system is 490 scfh. A "zero" reading from this meter is assumed to be a flow of one-half the minimum detectable flow (i.e., 245 scfh). This is slightly less than the permitted compressor seal leakage rate of 311 scfh that enters the acid gas flare header.

THERMAL OXIDIZER PILOT FUEL GAS METERING SYSTEM – The electronic Rosemount Model 3035 Multivariable Mass Flow Transmitter with a Daniels senior orifice meter is installed on the inlet fuel gas line to the Thermal Oxidizer. The transmitter is connected to POPCO’s distributed control system (DCS) in which the pilot fuel gas flow rate will be transmitted in units of “scfh”. The continuous metering equipment monitoring the pilot fuel gas flow is designed to measure flow rates and volumes up to 2000 scfh.

4.5.5 Mitigation of SRU Failures and Acid Gas Releases to the ZTOF: As previously analyzed in POPCO's *1983 Flaring Analysis*, two SRUs were originally intended to be operating, and only one was deemed likely to fail at a time. Such a failure produces a significant spike in SO_2 emissions, but one that in the 1983 analysis was predicted to not create a localized violation of a state or federal ambient air quality standard for SO_2 in effect at that time. However, the current single-SRU design doubles the potential SO_2 emissions associated with this failure scenario, as the entire acid gas rate associated with a 60 LTD SRU acid gas capacity could go to the ZTOF. As a result, ATC 9047 performed an Air Quality Impact Analysis ("AQIA") of this scenario, and a POPCO proposed mitigation of its impact, in accordance with APCD rules and Santa Barbara County FDP land use condition E-5. This analysis has shown that POPCO's proposed SRU failure mitigation system is anticipated to prevent a localized, short-term violation of any state and federal SO_2 ambient air quality standard.

4.5.6 Mitigation of Planned ZTOF Operations during Maintenance and Startup Activities: The ZTOF is also used to safely flare gases in a planned manner. Planned flaring is defined (pursuant to APCD Rule 359) as *"...a flaring operation that constitutes a designed and planned process at a source, and which would have been reasonably foreseen ahead of its actual occurrence, or is scheduled to occur*". As such, planned uses of the ZTOF are considered to be clearly within the control of POPCO in regards to schedule, duration, and rate of flaring. It should also be noted that the ZTOF is not operating in these planned activities as a "safety" device; it is however disposing of the flared gases in a safe manner (such that no fire or explosive atmospheres result). During evaluation of ATC 9047, it became apparent that an AQIA was required for the reasonable "worst-case" use of the ZTOF during planned activities; this worst-case activity is that of facility "Start-up" in which off-specification and equipment purge gases are safely vented to the ZTOF. This unavoidable activity is needed to safely bring the facility's gas processing equipment into operations. To minimize the time required to accomplish this activity, POPCO has desired as high an allowed volumetric flow rate limit as is permissible. However, an AQIA analysis was performed and it discovered that the permitted limit for planned activities of 1.5 MMSCF/hr for 12 hours in duration contained in PTO 8092 was predicted to create a violation of the 1-hour primary ambient air quality standard for NO_2. The analysis also indicated that at one-half the flow rate, and twice the duration (to 24 hours), the NO_2 standard and any other standard would not be exceeded. As a result, ATC 9047 was conditioned to restrict ZTOF operations during any planned use to no more than 0.75 MMSCF/hr and up to a continuous 24 hours in duration. This restriction does not reduce the total quantity of emissions from this activity; it does however reduce its peak hourly emissions impact.

4.6. Tanks/Sumps/Separators

4.6.1 General:

TANKS: There are three types of atmospheric storage tank systems operating at this facility that contain process fluids that have contacted hydrocarbons. These are the Stretford Oxidizer tanks, the wastewater tanks and the methanol tank. The source tests completed for wastewater tank T-601 confirmed that tank T-601 has the potential to emit ROC compounds in addition to odorous sulfur compounds. For the Stretford Oxidizer tanks, testing during the SCDP of ATC 9047 confirmed that ROC emissions occur from the atmospheric venting of Stretford oxidation air. The ROCs are emitted because the Stretford solution has come into direct contact with a stream that contains low concentrations of hydrocarbons.

VESSELS*:* All pressure vessel PRDs in this facility are either connected to the plant's hydrocarbon or acid gas flare manifolds. Permitted emissions of ROCs from pressure vessels are therefore only due to fugitive hydrocarbon leaks from valves and connections.

4.6.2 Emission Factors: Emissions from the Stretford oxidizer tanks are based on an emission factor of 0.10 lb/hr that was provided by POPCO. Emissions from the methanol tank are based on the ideal gas law and vapor displacement during tank fillings. Emissions from the methanol tank are based on the ideal gas law and one tank loading operation per year. Emission factors for the wastewater tanks are based on the ARB/KVB Method for determining fugitive hydrocarbon emissions. The wastewater tanks are assumed to operate in secondary, light-oil service.

4.6.3 Emission Controls: Carbon canister emission controls are used on wastewater tanks T-807 and T-601 to minimize any potential odorous compounds. There are no controls on the Oxidizer Tanks. The methanol tank is equipped with a submerged fill pipe and a pressure-vacuum relief valve per Rule 326.D.1a and D.2.a, respectively.

4.7. Vapor Recovery Systems

4.7.1 Drain Systems: A gas eductor system (J-203) creates a vacuum to remove vapors emitted into the plant's Pressure Drain System ("PDS"), TEG Drain System ("TDS"), and Sulfinol Drain Systems ("SDS"). In addition, this system serves the pipeline pig receiver. This gas eductor system prevents the release to the plant Acid Gas flare system of routine, intermittent sour-vapor releases through the PDS, TDS and SDS equipment from blowdowns of level-control gages and sight glasses. Without this vapor recovery system, these blowdowns would emit vapors to the PDS, TDS, and SDS equipment that sometimes exceed the sulfur limits authorized by APCD Rule 359 (i.e., 239 ppmv) for planned flaring activities. The recovered vapor will be returned by the eductor system for processing by the plant's existing fuel gas contacting system (V-211 and V-203). This system is comprised of valves, fittings, and hard piping. ROC emissions generated from this vapor recovery system components are calculated as part of the facility fugitive emissions inventory.

4.7.2 NGL Loading Rack: The NGL loading rack is equipped with a hard piped vapor recovery line. With this system, vapors from pressurized tank trucks are returned to the facility NGL tanks via a vapor balance line. This system is comprised of valves, fittings, and hard piping. ROC emissions generated from this vapor recovery system components are calculated as part of the facility fugitive emissions inventory.

4.8. Other Emission Sources

4.8.1 Pigging: Pipeline pigging operations occur at the Gas Plant. The pig receiver is de-pressured to the Pressure Drain System vapor recovery system. The receiver is purged with nitrogen prior to opening the unit to the atmosphere, as such there is no potential to vent hydrocarbons due to this process besides those associated with fugitive emissions from valves and fittings.

4.8.2 General Solvent Cleaning/Degreasing: Solvent usage (not used as thinners for surface coating) occurring at the POPCO facility as part of normal daily operations includes cold solvent degreasing and wipe cleaning. Mass balance emission calculations are used assuming that all the solvent used evaporates to the atmosphere unless an APCD-approved Solvent reclamation is used.

4.8.3 Surface Coating: Surface coating operations typically include normal touch-up activities. Entire facility painting programs are performed once every few years. Emissions are determined based on mass balance calculations assuming that all solvents evaporate to the atmosphere. Emissions of PM/PM_{10} from paint overspray are not calculated due to the lack of established calculation techniques.

4.8.4 Abrasive Blasting: Abrasive blasting with CARB-certified sands may be performed as a preparation step prior to surface coating. Particulate matter is emitted during this process. A general emission factor of 91 pound PM per 1000 pound of abrasive and 13 pound PM_{10} per pound abrasive is used (USEPA, 5^{th} Edition, Supplement D, Table 13.26-1, 9/97) to estimate emissions of PM and PM_{10}.

4.9. BACT/NSPS/MACT

4.9.1 BACT: Best Available Control Technology is required for certain emission units and processes for ROC and SO_x. The applicable BACT control technologies and the corresponding BACT performance standards are listed in Table 4.5 through 4.8. Table 4.1 lists the BACT requirements for the APCD approved Rule 331 Fugitive Hydrocarbon I&M Plan. Figure 4.1 identifies the location of analyzers used in determining compliance with BACT requirements for the SRU.

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

4.9.2 Rule 331 BACT Determinations: Pursuant to Sections D.4 and E.1.b of Rule 331, components are required to be replaced with BACT in accordance with the APCD's NSR rule. These BACT determinations are based on a case-by-case basis following the APCD's guidance document for determining BACT due to Rule 331. Rule 331 BACT determinations are documented in Table 4.2 through Table 4.4.

4.9.3 NSPS: Discussion of applicability and compliance with New Source Performance Standards is presented in Table 4.6. An engineering analysis for the affected equipment is found in the sections above.

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

4.9.5 MACT: On June 17, 1999, EPA promulgated Subpart HH, a National Emission Standards for Hazardous Air Pollutants (NESHAPS) for Oil and Natural Gas Production and Natural Gas Transmission and Storage. POPCO submitted an *Initial Notification of Applicability* by June 17, 1999. Based on that submittal, and several subsequent correspondences from POPCO (2/15/02 and 5/14/02), the APCD determined that only the NGL storage vessels are subject to MACT standards (40 CFR 63.776 (b) (2)). The storage vessels are operated as a closed system with no detectable emissions, so POPCO is in compliance. In addition, the sulfinol glycol regeneration system is subject to MACT control requirements. Compliance with these standards is achieved by routing the vapors to the sulfinol reboiler heater. Since these vapors are introduced with the primary fuel, no monitoring or testing requirements apply (40 CFR 63.772.e.1.iii and 40 CFR 63.773.d.2.i). General MACT requirements applicable to this facility are contained in Condition 9.B.18.

4.10. Best Available Retrofit Control Technology (Fugitive Emissions)

During the processing of ATC 9047, an analysis of what constituted Best Available Retrofit Control Technology ("BARCT") was jointly performed by the APCD and POPCO to identify a suitable fugitive emissions mitigation approach short of obtaining ROC emission offsets. BARCT should identify an emission limitation that, according to the California Health and Safety Code, Section 40406: *"...is based on the maximum degree of reduction achievable, taking into account environmental, energy, and economic impacts of the class or category of source"*. The APCD and POPCO also agreed that if application of BARCT resulted in the facility's ROC NEI dropping below the 25.0 tpy ROC offset threshold of Rule 205.C, no ROC offsets would be required.

To reconcile the fact that full BARCT is cost-effective, yet not fully achievable in the short construction window, the APCD and POPCO also developed a "deferred" retrofit BARCT program that applies to the remaining existing valves left in-service after construction is completed.

The BARCT analysis performed by the APCD and POPCO as part of ATC 9047 identified equipment and techniques to reduce fugitive emissions from the existing facility valves and connections. The basic requirements of the BARCT plan resulted in the retrofit of the existing facility components during the expansion construction of sealless valves in unsafe to monitor locations; replacement of standard valves with low emission packing ("LEP") design valves; a modified LDAR threshold for all remaining in-service standard valves (BARCT retrofit or not) and threaded static connection leak-paths; and a reduction of the "minor" leak LDAR threshold for all existing valves (constituting the "deferred" BARCT retrofit program). The specific details of the total BARCT program are specified in a permit condition in Section 9.C.

These elements of BARCT taken together were anticipated to immediately reduce the facility's current emissions by 35.32 tons/year, and to be accomplished at a cost effectiveness of $6,642/ton ROC reduced. Further, a requirement that BARCT retrofit technology be applied to any standard valve which cannot be repaired to below 500 ppmv during the quarterly LDAR activities, are estimated to generate additional, but unquantified emission reductions over the remaining life of the facility after the expansion was completed.

4.11. CEMS/Process Monitoring/CAM/Meter Calibration

4.11.1 <u>CEMS</u>: In 1983, and pursuant to PTO 4078, the APCD determined the emission sources and operating parameters that need continuous monitoring to ensure permit compliance. Tables 4.9 through 4.12 identify the current set of emission sources and operating parameters that require continuous monitoring pursuant to this permit. In order for the APCD to assess facility operational status and to ensure major emission sources are operating properly, selected monitored data are connected to and telemetered to the Data Acquisition System ("DAS") at the APCD's office on a real-time basis; these parameters are also listed and specified in Tables 4.9 through 4.12.

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

The monitors must meet the requirements set forth in APCD Rule 328 and the Code of Federal Regulations (CFR), 40 CFR Parts 51, 52 and 60. These must be installed in accordance with manufacturer's specifications, and EPA requirements as specified in the CFR.

POPCO must obtain the APCD's approval of any modifications/updates to the current CEMS Plan. POPCO is required to follow the APCD *Continuous Emission Monitoring Protocol Manual*

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

- B-801A/B Fuel Flows
- B-801A/B Incineration Zone Temperature Indicator(s)
- B-801A/B SO_x and NO_x mass emission CEM systems
- Stretford Unit Tailgas H_2S concentration analyzer
- Stretford Unit Tailgas Flow to B-801A/B
- Acid Gas to SRU Inlet flow meter
- Plant inlet sour gas flow rate, and H_2S concentration analyzer
- Plant outlet sales gas flow rate and H_2S concentration analyzer
- Flare header flow meters (acid gas and hydrocarbon manifolds)
- Compressor seal leakage to flare header flow meters (meter required for each compressor)
- Hour meters (emergency generator, emergency generator for the instrument air compressor and firewater pumps)
- Production meters (NGL shipped via truck, elemental molten and Stretford sulfur products, produced water via truck)
- TEG Reboiler fuel meters
- SRU Steam Generator fuel meter

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

4.11.3 CAM: *ExxonMobil – 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. Currently no units at POPCO require a CAM plan.

4.11.4 Meter Calibration: To ensure that appropriate calibration and maintenance procedures are applied to the metering specified above, a *Process Monitor Calibration and Maintenance Plan* is required from POPCO. This Plan shall take into consideration manufacturer recommended maintenance and calibration schedules, as well as the following supplemental requirements:

- The sour gas flow meter and inlet H_2S analyzer shall follow the requirements in the APCD's CEM Protocol document.

- The Stretford H_2S analyzer and tailgas flow meter shall follow the CEM Protocol document.

- The Utility Boiler NO_x and SO_x CEMS system shall follow the CEM Protocol document.

- Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized.

4.12. Source Testing/Sampling

4.12.1 Source Testing: Source testing and sampling are required in order to ensure compliance with permitted emission limits, BACT, NSPS, prohibitory rules, control measures and the assumptions that form the basis of this operating permit. Tables 4.13 through 4.15 detail the emission units, pollutants and parameters, methods and frequency of required testing. POPCO is required to follow the APCD *Source Test Procedures Manual* (May 24, 1990 and all updates).

The parameters to be source tested annually (unless otherwise specified). The APCD may require additional source testing if problems develop or if unique circumstances occur that warrant special testing. The following emission points and control/monitoring systems are required to be source tested:

- Sulfur Recovery Unit/Stretford Tailgas Plant (percent mass H_2S and TRS reduction)
- Boilers B-801A/B (NO_x , SO_x, ROC and CO)
- Functional testing of the SRU Failure shutdown system to ensure excess SRU acid gas will not be flared subsequent to any unplanned SRU failure.
- SRU's Stretford Unit Oxidizer Tanks (ROC)
- Wastewater Tanks T-601 and T-807 – ROC testing performed biennially, if in operation, using APCD approved test methods.

4.12.2 Sampling: Duplicate samples of the process streams below are required to be sampled and analyzed on a quarterly basis. A third party lab shall perform all analyses, except for daily sorbent tube samples.

- Feed Gas (sour): Sample taken at sample probe of inlet H_2S analyzer. Analysis for hydrogen sulfide and total sulfur composition.
- Boiler Fuel Gas: (a) Weekly sorbent tube for hydrogen sulfide; (b) Quarterly sampling for hydrogen sulfide and total sulfur composition.
- Sales (PUC Quality) Fuel Gas: Analysis for: HHV, total sulfur, hydrogen sulfide.
- Stretford Tailgas to Boilers: Analysis for: HHV

As necessary to ensure compliance with this permit and applicable rule and regulations, the APCD may require POPCO, by written notice, to sample additional process streams in a manner and frequency specified by the APCD. All sampling and analyses are required to be performed according to APCD-approved procedures and methodologies. Typically, the appropriate ASTM methods are acceptable. All sampling and analysis must be traceable by chain of custody procedures. POPCO shall obtain APCD approval of all sampling and analytical methods used to obtain the process stream data stated above. Section 9 details the sampling that is required.

4.13. Odor Monitoring

POPCO shall implement the APCD-approved *Odor Monitoring Plan* for ambient odor monitoring and a human olfactory verification program for the life of the POPCO facility. The site identified in Table 4.16, *LFC Odor*, shall monitor the parameters identified in Table 4.16. Other odor-related pollutant -specific monitoring equipment may be added to the stations, if deemed necessary by the APCD.

4.14. Part 70 Engineering Review: Hazardous Air Pollutant Emissions

Hazardous air pollutant emissions from the different categories of emission units at the POPCO facility are based on emission factors listed in USEPA AP-42. Where no emission factors are available, the HAP fractions from the ARB VOC Speciation Manual – Second Edition (April 2002) are used in conjunction with the ROC emission factor for the equipment item in question.

Potential HAP emissions from each emissions unit at the POPCO facility are listed in Section 5.

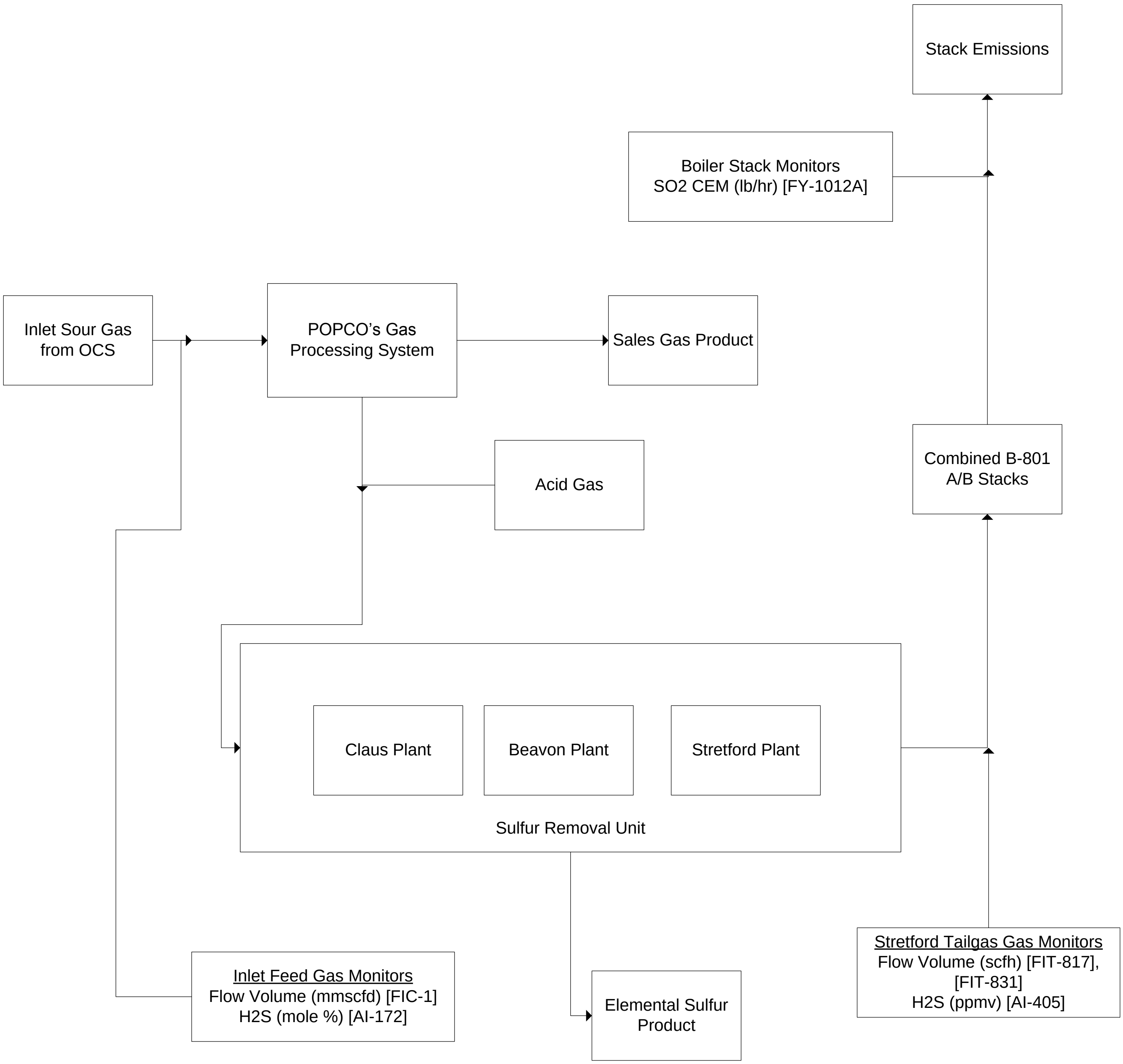


Figure 4.1 POPCO SRU BACT & NSPS Monitoring Systems

Table 4.1 Rule 331 Fugitive Hydrocarbon Inspection and Maintenance Program

	Standard Rule 331 Requirements	Existing Components (Subject to BARCT) [b.]	New Components (Subject to BACT) [a.]	Enhanced Fugitive I&M Requirements
Valves				
Leak Definition [d, e]	Gaseous: 1,000 ppmv	Gaseous: 500 ppmv	Gaseous: 100 ppmv	Gaseous: 100 ppmv
Monitoring [f, g]	Quarterly	Quarterly	Quarterly	Quarterly
Relief Valve Monitoring	Gaseous: Vented to flare	Gaseous: Vented to flare	--	--
Pump Monitoring	Gaseous: Dual Seals, monthly [j]	Gaseous: Dual Seals, monthly [j]	Gaseous: Dual Seals, monthly [j]	--
Flanges/Connections				
Leak Definition [d, e]	Gaseous: 1,000 ppmv	Flanges: 1,000 ppmv Static Threaded Connection: 500 ppmv [C. D]	Gaseous: 100 ppmv	Gaseous: 100 ppmv
Monitoring [k, l]	Annual	Annual	Annual	Quarterly[f]
Compressors				
Monitoring [m]	Gaseous: Vented to vapor control system	Gaseous: Vented to vapor control system	Gaseous: Vented to vapor control system	--
Open-Ended Lines				
Monitoring [k, l]	Capped	Capped	Capped	--
Repair Requirements [n, o, p]	First attempt within 5 calendar days. Repair within 15 calendar days.	First attempt within 5 calendar days. Repair within 15 calendar days. [b]	First attempt within 5 calendar days. Repair within 15 calendar days.	First attempt within 5 calendar days. Repair within 15 calendar days [c]
Recordkeeping and Reporting Requirements [q]	Similar to NSPS Subpart KKK	Similar to NSPS Subpart KKK	Similar to NSPS Subpart KKK	Similar to NSPS Subpart KKK

NOTE: These requirements are in addition to APCD Rule 331 and permit requirements. Where a conflict may occur, the requirement more protective to air quality (as determined by the Control Officer) shall apply

a. BACT. applies to all components permitted on or after February 4, 1997. Similar to New Source Performance Standards (NSPS); Equipment Leaks of VOC from Onshore Natural Gas Processing Plants; Final Rule, 40 CFR Part 60 Subpart KKK, FR Vol. 50, No. 121, June 24, 1985. Applicable to equipment in VOC service (that is, contains or contacts a process fluid that is at least 10 percent VOC by weight at 150ºC) or in wet gas service (that is, contains or contacts inlet gas before the plant extraction process). All components identified for I&M shall be uniquely tagged, in an APCD-approved manner, to distinguish these components from the components approved prior to that date.

Best Available Retrofit Control Technology (BARCT) Program

Applies to all components permitted before February 4, 1997. Applicable to components in gaseous and light hydrocarbon services, that is, contains or contacts a process fluid that is equal to or greater than 10 percent VOC by weight at 150ºC or in wet gas service (that is, contains or contacts inlet gas before the plant extraction process). All existing components identified for I&M shall be uniquely tagged, in an APCD-approved manner, to distinguish these components from components permitted on or after February 4, 1997.

b. Any standard-stem valve subsequent to repair per Rule 331 and which leaks between 501 and 1000 ppmv, is subject to BARCT retrofit with LEP technology within 1 calendar year of the date of failed repair. LEP is an acronym for Low Emissions Packing technology valve stem seal system. See APCD Policy and Procedure 6100.061 for definition of LEP.

Enhanced Fugitive Hydrocarbon Inspection and Maintenance Program

c. The minor leak threshold for repairs is defined as 500 ppmv for those valves and flanges/connections subject to the Enhanced Fugitive I&M Program defined in DOI 0034.

Gas Components Leak Detection

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

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

Valves

f. Reductions in fugitive emissions due to the implementation of the Rule 331 APCD I&M Programs assume that all valves are accessible to quarterly monitoring.

g. The quarterly valve monitoring program required by the APCD is similar to that of the NSPS valve monitoring program. NSPS requirements, subpart KKK (and VV) requires leak screening during initial first two months of operations of any new valve.

Connections

h. The same record keeping and reporting procedures as NSPS are also required for connections; alternatively, a procedure approved by the Air Pollution Control Officer can be used.

i. It is assumed that the total connection count includes all connections required for the venting of relief valves to a vapor control system, the capping of open-ended lines, and the conversion of sampling to a closed purge system.

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

Pumps

k. The APCD I&M program on pumps with dual mechanical seals is similar to that required by NSPS on pumps with single seals. This also includes single seals on the sweet crude oil rover sample pump, PBE-1349, PBH-3334 and PBE-3335.

Compressors

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

Repair Requirements

m. Repair requirements follow NSPS requirements.

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

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

Record Keeping and Reporting Requirements

p. Record keeping and reporting requirements follow the most stringent of NSPS requirements.

Component Accessibility

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

Table 4.2 Rule 331 BACT Component Requirements

Tag No.	Component Type	Component Location	Plant/ P&ID	BACT Install Date	BACT Performance Standard	Notes
PO 21H-024	Valve	Union type bonnet of block valve installed on top of vessel V-104.	PO 21H	6/2/2000	100 ppmv	
PO 21H-024	Valve	Threads on body of valve at top of vessel V-104	PO 21H	4/27/2001	100 ppmv	Removed from service.
PO 21DD-02	Other	Front cover.	PO 21DD	7/24/2002	100 ppmv	
PO 21A-170	Other	V-50TT-1B Mezzanine Above V-50E	PO 21A	3/22/2004	100 ppmv	

Table 4.3 BACT Emission Unit/Process: Fugitive Emissions from Valves and Connections in Hydrocarbon Service

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
ROC	Valves 1) Use of Sealess valves (e.g. Bellows) or low-emissions packing ("LEP") systems; 2) Fugitive emissions Leak Detection and Repair ("LDAR") program consistent with Rule 331 LDAR requirements, and 40 CFR subpart KKK frequencies.	LDAR minor leak threshold @ 100 ppmv THC per Method 21	1) APCD inspection during SCDP to verify component counts and configuration specified herein; 2) Periodic APCD inspection of POPCO records pursuant to Rule 331. New valves to be uniquely "tagged" to differentiate BACT LDAR threshold.
	Connections (Flanges and Threaded Fittings) 1) Flange gaskets; graphitic-type or equivalent District-approved type, rated to 150 percent of process pressure at process temperature; 2) Static threaded connections maintained at <100 ppmv; 3) All connections subject to LDAR consistent with Rule 331 LDAR requirements, and 40 CFR subpart KKK frequencies.	LDAR minor leak threshold @ 100 ppmv THC per Method 21	1) APCD inspection during SCDP to verify component counts and configuration specified herein; 2) Same as 1) 3) Periodic APCD inspection of POPCO records pursuant to Rule 331. New connections to be uniquely "tagged" to differentiate BACT LDAR threshold.

Note: LEP valve systems are considered to employ one of the following types of valve actuator sealing systems: quarter turn; live-loaded packing; graphite or PTFE packing, precision machine stem; or other APCD-approved system.

Table 4.4 BACT Emission Unit/Process: Fugitive Emissions from Pressure Relief Devices, Compressors, and Pumps in Hydrocarbon Service

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
ROC	Pressure Relief Devices		
ROC	1) All new PRD reliefs to be routed via a closed vent system to the facility flare (i.e., the "ZTOF").	The combined capture/destruction efficiency of the system which handles PRD reliefs is a minimum of 98 percent ROC by weight.	1) APCD inspection during SCDP to verify component counts and configuration specified herein. 2) The hard-piped vent system, and the ZTOF meets the capture/destruction efficiency requirement.
	Compressor		
	1) Double mechanical seals with barrier fluid; or, 2) Route seal leakage emission points to closed vent system; 3) Subject to LDAR inspection pursuant to Rule 331 and 40 CFR subpart KKK frequencies.	1) Not applicable; see 2) below 2) New compressor's (K-300C) seal leakage is vented to the ZTOF system which can destroy ROCs to a minimum of 95 percent mass destruction efficiency; 3) LDAR leakage performance standard of any piping connection, or atmospheric compressor seal, on or to compressor is 100 ppmv per Method 21.	1) APCD inspection during SCDP to verify component configuration specified herein; 2) Periodic APCD inspection of POPCO records pursuant to Rule 331. New compressor to be uniquely "tagged" to differentiate BACT LDAR threshold.
	Pumps (in Liquid Service)		
	1) Equipped with double mechanical seal and barrier fluid systems; 2) Subject to LDAR inspection pursuant to Rule 331 frequencies, and 40 CFR subpart KKK frequencies.	Seal leakage LDAR threshold at 500 ppmv per Method 21.	1) APCD inspection during SCDP to verify component counts and configuration specified herein; 2) Periodic APCD inspection of POPCO records pursuant to Rule 331. New pumps to be uniquely "tagged" to differentiate BACT LDAR threshold.

Table 4.5 BACT Emission Unit/Process: Sulfur Recovery Unit (SRU)

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
SO_x as SO_2	Three stage conversion process of H_2S in acid gas from Sulfinol Amine System, to elemental sulfur ◊ *First stage*: liquid oxygen enhanced, Claus-type catalytic reduction of H_2S to molten elemental sulfur; without acid gas enrichment recycle. ◊ *Second stage*: Beavon-type catalytic reduction of Claus tailgas SO_x to H_2S. ◊ *Third stage*: Stretford H_2S removal process of Beavon tailgas; produces wet elemental sulfur cake	<u>At all SRU Acid Gas Feed Capacities</u> (0 LTD to 60 LTD) The more stringent of the following two requirements: 1) 99.9 percent by mass H_2S removal efficiency across the SRU, including sulfur removed by Stretford unit; or, 2) 100 ppmv, dry basis, Stretford Tailgas H_2S limit prior to incineration; and, No more than 2.89 lb/hr of H_2S in Stretford Tailgas or an equivalent SO_2 mass limit of 5.44 lb/hr to the boilers from Stretford Tailgas. <u>Transient Operations</u> *Startups & Scheduled SRU Shutdown*[1, 2]: 3) SO_2 mass limit of 5.67 lb/hr from B-801A & B stacks.	<u>All Operating Modes</u> 1) Mass H_2S removal efficiency, as follows: • Certified & calibrated inlet H_2S analyzer • Certified & calibrated inlet sour gas feed flow meter • B-801A/B SO_2 mass emissions CEM 2) Stretford Tailgas H_2S ppmv: • Certified & calibrated tailgas H_2S analyzer • Certified & calibrated Stretford tailgas flow meter 3) B-801A/B SO_2 mass emissions CEM: • Certified, calibrated and operated pursuant to 40 CFR and District CEMS Protocol.

NOTES:

1. SRU Startups are defined as the first 12 hours of SRU operation following a complete loss of platform gas feed for one hour or longer.
2. SRU Shutdowns are defined as the 48-hour period immediately preceding a scheduled shutdown of the SRU. The beginning of the 48-hour period shall commence when platform gas feed is curtailed. During this time, the SRU is operated in a manner so as to safely prepare the catalyst bed for shutdown.

Table 4.6 BACT Emission Unit/Process: Sulfur Recovery Unit Failure and Natural Gas Combustion

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
SO_x	<u>SRU Failure Mitigation System</u> 1) POPCO to install a system which prevents excess flaring of acid gas: Section 9.C of this permit and Section 10.2 of ATC 9047 specify the process controls and sensors used to prevent flaring of SRU feed acid gas in excess of 1450 SCF which may be generated by the Sulfinol regenerator upon an unexpected SRU failure and shutdown.	APCD BACT standard for mitigating potential violations of SO_2 AAQS caused by unplanned SRU acid gas flaring is, as follows: ⇒ First, equipment and/or process controls must be considered to reduce the acid gas flow rate and/or quantity of acid gas flared such that no SO_2 AAQS violation occurs; or, ⇒ If no mitigation system is technically or safely feasible to eliminate a SO_2 AAQS violation, then a system shall be installed to reduce by a minimum of 90% by weight the potential uncontrolled acid gas released during the worst-case SRU flaring event; (the 90% standard may be relaxed with APCD concurrence that justifiable engineering or safety considerations prevent attainment of the 90% standard).	• APCD inspection during SCDP to verify system configuration specified in Section 9.C of this permit and Section 10.2 of ATC 9047.
	<u>Natural Gas Combustion Processes</u> 1) Regenerable Sulfinol amine-based solutions clean the raw sour-gas of H_2S to <6 ppmv. Residual total sulfur content of any cleaned fuel gases is less than 24 ppmv total sulfur. Absorbed acid offgas produced from regenerated amine solution processed by the facility SRU.	⇒ All natural gas fuels and purge gases limited to 24 ppmv total sulfur content.	• Section 9.C of this permit.

Table 4.7 BACT Emission Unit/Process: Solvents

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
ROC	Use of Low VOC or Water-Based Solvents (where feasible)	⇒ APCD-approved BACT Solvent List	Condition 9.C

Table 4.8 BACT Emission Unit/Process: Planned Flaring

Pollutant	Control Technology	Emission Limit/Performance Standard	Verification / Recordkeeping Requirements
ROC, SOx	Thermal Oxidizer	⇒ Use of purge gas that meet sales gas quality ⇒ Properly maintained thermal oxidizer combustors ⇒ Use of sales gas in the compressors ⇒ Limit the sulfur content of the purge gas to 80 ppmv total sulfur and 4 ppmv H_2S (sales gas quality – PUC Quality)	Implementation of a *Thermal Oxidizer Combustor Maintenance Plan* / Section 9.C

Table 4.9 Parameters to be Continuously Monitored: Sulfur Recovery Unit (SRU)

Parameter Monitored	Instrument Tag No. [8]	DAS Variable[1]	Monitored Units	Permit Limit	Averaging Period	Footnote Comments
Inlet Sour Gas Feed Flow	FIC-1	INGASFLO	MMSCF/D	80	Daily	1, 6, 7, 9
Inlet Sour Gas H_2S Content	AI-172	INGASH2S	Mole % H_2S	2.67	6-minute	1, 5, 6, 7, 9
Stretford Tailgas H_2S Content	AI-405	TAILH2S	ppmvd H_2S	100	6-minute	1, 2a, 5, 6, 7, 9
Stretford Tailgas Flow to Boilers	FIT-817A, FIT-831A	TAILGFLO ATGFLOW BTGFLOW	SCFH	None	6-minute	1, 6, 7, 9
Combined Boiler SO_x as SO_2 Emissions	FY-1012A	ABSO2LB	lb/hr SO_2	5.67	6-minute and Sliding Hour	1, 2a, 5, 6, 7, 9
SRU Claus Elemental Sulfur Production	Not Applicable		LTD			4
SRU Stretford Sulfur Production	Not Applicable		Mass per shipment			4

Compliance Formulae

BACT for H_2S Removal
FIC-1 = (FY1) – (FT-196)
FI-405 = (FIT-817A) + (FIT-831A)
Where:
FY1 = Total Sour Gas Feed Flow   FT-196 = Sour Gas to LFC

Inlet H_2S, lb/hr =

$$F = [FIC - 1] * \left(\frac{[AI - 172] * 34 * 10^6}{24 * 379 * 100} \right)$$

Stretford H_2S, lb/hr =

$$S = [FI - 405] * \left(\frac{[AI - 405] * 34}{379 * 10^6} \right)$$

SRU, % H_2S mass removed = (F-S)/F * 100%

NSPS Subpart LLL Equivalent Performance for Total Sulfur Removal

Inlet Total Sulfur (as SO_2), lb/hr = "T" = "F" (see above) * (64/34)
Combined Boiler Stack Sulfur Emissions as SO_2, lb/hr = "E" = (FY-1012A)
SRU, % Total Sulfur removed = (T-E)/T * 100%

Table 4.10 Parameters to be Continuously Monitored: Boilers

Parameter Monitored	Instrument Tag No. [8]	DAS Variable[1]	Monitored Units	Permit Limit	Averaging Period	Footnote Comments
Stack Emissions from Boiler A	AI-810B	ANOXPPMC	ppmv NO_x (uncorrected)	--	6-minute	4, 6, 7, 8
	FY-810B	ANOXLB	lb/hr NOx	1.48	6-minute and Sliding Hour	2a, 4, 5 ,6
		ASO2LB	lb/hr SOx	0.11	6-minute and Sliding Hour	4, 5 ,6
Stack Emissions from Boiler B	AI-812B	BNOXPPMC	ppmv NO_x (uncorrected)	--	6-minute	4, 6, 7, 8
	FY-812B	BNOXLB	lb/hr NOx	1.48	6-minute and Sliding Hour	2a, 4, 5 ,6
		BSO2LB	lb/hr SOx	0.11	6-minute and Sliding Hour	4, 5 ,6
Combined Stack Emissions from Boiler A and B	FY-810A & FY-812A	ABSO2LB	lb/hr SOx	5.67	6-minute and Sliding Hour	
Fuel Feed Rate to Boiler A	FIC-818	AFUELGAS	scfh	27,948	Hourly Average	
Fuel Feed Rate to Boiler B	FI-832	BFUELGAS	scfh	27,948	Hourly Average	
Boiler Incineration Zone Temperature for Boiler A	TIC-812	ATEMP	degrees F	919	Daily Average	2b
Boiler Incineration Zone Temperature for Boiler B	TI-821	BTEMP	degrees F	919	Daily y Average	2b
Stack Volume Flow Rate from Boiler A	FI-807A	ASTKFLOW	kscfh			5, 6
Stack Volume Flow Rate from Boiler B	FI-835A	BSTKFLOW	kscfh			5, 6

Table 4.11 Parameters to be Continuously Monitored: ZTOF Thermal Oxidizer[3]

Parameter Monitored	Instrument Tag No. [8]	DAS Variable[1]	Monitored Units	Permit Limit	Averaging Period	Footnote Comments
HC Manifold Gas Flow Rate	GF90, Diamond II annubar	HCHEADER	scfh	500	Hourly Average	2a, 6, 7
Acid Gas Manifold Gas Flow Rate	GF90	AGHDRFLO	scfh	500	Hourly Average	2a, 6, 7
Pilot Temperature	ALH-804	PILOTTMP	degrees F			2b
Pilot and Purge Gas Flow Rates						6
Flare Gas Sampling						
Compressor Seal Leakage Rates						6

Table 4.12 Parameters to be Continuously Monitored: Gas Processing[3]

Parameter Monitored	Instrument Tag No. [8]	DAS Variable[1]	Monitored Units	Permit Limit	Averaging Period	Footnote Comments
Sales Gas Stream	AI-331	2H2SS	ppmv H_2S	4	6-minute	7, 9, 10

NOTES

1. Parameters to be telemetered and connected to the DAS.
2. Equipped with alarm configured internally to the APCD DAS system:
   a) Equipped with High in plant alarm.
   b) Equipped with Low in plant alarm.
   c) Equipped with Hi/Low in plant alarm.

3. Continuous monitoring of other parameters is not required initially. However, the APCD may request that monitors for other parameters be installed in the future.
4. Production records will be maintained through the volume of produced sulfur sold. The quantity of produced sulfur will be determined by State certified truck scales.
5. DAS to be configured with high or low process-alarm at the APCD based on telemeter DAS data.
6. Permanent recording of parameter raw data required via strip-chart, circular chart, or computer printout.
7. Parameters to be included in quarterly reports. The APCD may request additional information be presented in quarterly reports if necessary.
8. Nomenclature indicates a POPCO-specified process indicator/device tag number.
9. Indicates metering must be operated and maintained to meet APCD's *CEM Protocol*.
10. PPMV for NO_x corrected 3% oxygen and adjusted for TGU gas dilution effect per §9.C.1(a)(i) of this permit.

Table 4.13 Source Test Parameters for Boilers (B-801 A and B-801 B)

Emission & Test Points	Pollutants/Parameters [2]	Test Methods [1, 3]
Boiler Stacks [2]	NO_x - ppmv & lb/hr	EPA Method 7E
	CO - ppmv & lb/hr	EPA Method 10
	SO_x - lb/hr	EPA Method 6C, or CARB Method 100
	ROC – lb/hr	EPA Method 18
	Sampling Point Loc.	EPA Method 1
	Stack Gas Flow Rate	EPA Method 2
	O_2, CO_2, Dry Mole Wt	EPA Method 3
	Moisture Content	EPA Method 4
	Stack TRS/(SO_2 + TRS) ppmv Ratio	EPA Method 15
	Boiler Incineration Zone Temperature	(^{o}F)
Boiler	Fuel Gas Flow Rate	Plant Gas meter
Fuel Gas(es)	Higher Heating Value	ASTM D 1826-88
	Total Sulfur Content [4]	ASTM D 1072
Inlet Feed Gas	Flow rate (MMSCFD)	EPA Method 2, CEM Protocol
Inlet Feed Gas	H_2S Concentration (ppmv)	CEM Protocol
Stretford Tailgas	Tailgas Flow Rate	Stretford Tailgas Flow meter
Stretford Tailgas	Tailgas Composition [4]	ASTM 1945-81

BOILER STACK SOURCE TEST FREQUENCY REQUIREMENTS

Pollutant	Frequency
NO_x, CO ppm	Semiannual[6]
NO_x, CO lb/hr	Annual
SO_x	Annual
SO_2/TRS ratio	Annual
ROC	Biennial

SITE SPECIFIC REQUIREMENTS

1. Alternative methods may be acceptable on a case-by-case basis.
2. The emission rates shall be based on EPA Methods 2 and 4, or Method 19 along with the heat input rate.
3. For NO_x, SO_x, CO, ROC and O_2 a minimum of three 40-minute runs shall be obtained during each test.
4. Total sulfur content fuel samples shall be obtained using EPA Method 18 with Tedlar Bags (or equivalent) equipped with Teflon tubing and fittings. Turnaround time for laboratory analysis of these samples shall be no more than 24 hours from sampling in the field.
5. Source testing shall be performed for each boiler in an "as found" condition. Annually, at least one boiler shall be tested with Stretford tailgas combustion.
6. The boilers shall be tested for NO_x and CO twice per year, both tests shall determine compliance with the exhaust concentration limits of the permit. During one test compliance with the mass emissions limits of the permit shall be determined.

Table 4.14 Source Test Parameters for the SRU

Emission & Test Points	Pollutants/Parameters [2]	Test Methods [1, 3]	Frequency
Stretford Tailgas	Tailgas Flow Rate	Stretford Tailgas Flow meter	Annual
Stretford Tailgas	Tailgas Composition [4]	ASTM 1945-81	Annual

SITE SPECIFIC REQUIREMENTS

1. Alternative methods may be acceptable on a case-by-case basis.
2. The emission rates shall be based on EPA Methods 2 and 4, or Method 19 along with the heat input rate.
3. For SO_x and O_2 a minimum of three 40-minute runs shall be obtained during each test.
4. Total sulfur content fuel samples shall be obtained using EPA Method 18 with Tedlar Bags (or equivalent) equipped with Teflon tubing and fittings. Turnaround time for laboratory analysis of these samples shall be no more than 24 hours from sampling in the field.

Table 4.15 Source Test Parameters for the Wastewater Tanks (T-601 and T-807)

Emission & Test Points	Pollutants/Parameters	Test Methods [1, 2]	Frequency
	Total Hydrocarbons	EPA Method 25A	Biennial
	ROC – ppmv & lb/hr	EPA Method 18	Biennial

SITE SPECIFIC REQUIREMENTS

1. Alternative methods may be acceptable on a case-by-case basis.
2. For ROC a minimum of three 40-minute runs shall be obtained during each test.

Table 4.16 Requirements for Odor Monitoring

Parameters to be Monitored	LFC Odor [1]
H_2S	X
TRS	-
WS Avg.	X
WD Avg.	X
WS Result	X
WD Result	X
Sigma Theta	X
Int Temp.	X
Ext. Temp.	X

NOTES:

1 This station shall be located at the property boundary of the ExxonMobil LFC facility.

Table 4.17 NSPS LLL Compliance Requirements

Item	*Subpart LLL Section (§)*	*Subpart LLL Requirement Summary*	*Source Test Observation* [*Report Page*]
1	60.642 (a)	Initial SO_2 removal efficiency, "R" test per §60.8 and Subpart LLL, Table 1. Table 1 requires Z_i for: Y = 13.77% H_2S X = 15.86 LTD Z_i = 93.5 %	Test was done within 180 day window at 72.8 MMSCFD rate (97.1 % of maximum design feed rate). Y= 13.77% X= 15.86 LTD Observed R = 99.9% [Table 4-3]
2	60.642 (b)	*Ongoing Compliance with NSPS*	See EPA Subpart LLL Waiver letter of 11/19/96. POPCO monitors inlet sour gas H_2S content and total flow volume. PTO 8092 BACT standard for H_2S & TRS removal is greater than any applicable Subpart LLL requirement. Inlet H_2S analyzer (AI-172) passed RATA test on October 5, 1998.
3	60.643 (1)	R must be > or equal to Z_i per §60.642 (a).	Observed R = 99.9% [Table 4-3] R is > than Z_i as determined through 8/11/98 to 8/12/98 source testing.
4	60.643 (2)	*Ongoing Compliance with NSPS* R must be > or equal to Z_c per §60.642 (b).	PTO 8092 TRS removal efficiency requirements are more stringent than any Subpart LLL, Table 2 requirements for Z_c. Per EPA waiver, ongoing compliance with Z_c shall be based on compliance with PTO BACT requirements and the real-time monitoring of the SRU's TRS removal efficiency.
5	60.644	Initial compliance test analytical methods shall be followed.	Notwithstanding the 11/19/96 EPA waiver for acid gas flow measurements, all §60.644 test methods were followed to calculate X, Y and R of 60.642 (a). [Table 4-3]
6	60.646 (a)	*Ongoing compliance with NSPS*	See 11/19/96 EPA waiver and PTO 8092, Table 4.3 and Condition 9.C.7 requirements. R = (S-E)/S where S is inlet SO_2 equivalents in the sour feed gas. E is directly measured at the plant boilers SO_2 CEM.
7	60.646 (b)	*Ongoing Compliance with NSPS* Requires a SO_2 CEM where a reduction control system is followed by a continuous incineration device (i.e., the POPCO boilers), with the following additional requirements: (1) CEM measures atmospheric SO_2 emissions; and the span of the CEM shall be set so that the equivalent emission limit in §60.642(b) will be between 30% and 70% of the measurement range of the CEM. (2) An incineration combustion zone temperature monitor, accurate to +/- 1% of actual temperature, if ppmv of SO_2/(ppmv of SO_2 + TRS) $\leq$ 0.98 per §60.642 (a) tests, and temp monitoring to validate SO_2 CEM is measuring all TRS emissions. (3) A TRS monitor can be used in lieu of (2) above to calculated total sulfur emissions (E).	(1) POPCO CEM meets applicable 40CFR requirements. (2) Source tests showed that with maximum tailgas flow to one boiler and temperature of no less than 919 ^oF, that $SO_2/(SO_2+TRS)$ is $\leq$ 0.98 {0.993 actual ratio}. [Table 4-4] 919 ^oF is minimum boiler operating temperature when tailgas is being incinerated. (3) Not applicable to POPCO; see item (2) above.
8	60.646 (c)	Not applicable to POPCO.	Not applicable to POPCO
9	60.646 (d)	*Ongoing Compliance with NSPS*	Pursuant to an EPA-approved waiver, R is monitored

Item	*Subpart LLL Section (§)*	*Subpart LLL Requirement Summary*	*Source Test Observation* **[***Report Page***]**
		Average achieved sulfur emission reduction efficiency (R) shall be calculated for each 24-hour interval. The beginning and end of the 24-hour interval may be at any selected clock time, but it must be consistent. The 24-hour SO_2 reduction efficiency, R, shall be based on the 24-hour average of sulfur production rate (S) and the sulfur emission rate (E), consistent with the following subparagraph requirements: (1) data from 60.646(a) instrumentation shall determine S; (2) data from 60.646.(b) shall determine E. The E CEM must provide at least one data point in each successive 15-minute interval; at least two data points must be used to calculate each 1-hour average. A minimum of 18, 1-hour averages must be used to computed each 24-hour average.	by a mass balance of the inlet sulfur fed to the plant versus that emitted at the boiler stacks. The S production will the difference between the feed sulfur ("F") and E sulfur emitted, as follows: R = (F-E)/F = 1 – E/F (1) No elemental sulfur production, S, monitoring will be performed per the EPA waiver; (2) This PTO requires that six-minute average CEM data points be obtained for the E and feed sulfur, F, parameters, which are used to compute hourly and daily averages of R.
10	60.646 (e)	Alternative R monitoring protocol for source less than 150 LT/D capacity.	POPCO has not opted for this method.
11	60.646 (f) & (g)	*Ongoing Compliance with NSPS* Monitoring devices required per 60.646 (b)(1), (b)(3) and (c) of this section shall be calibrated at least annually per manufacturer's and §60.13(b) specifications, and otherwise shall be subject to the General Provisions requirements of §60.13(b).	POPCO's CEM Plan is required to meet these minimum requirements for the E and F CEM monitors.

5.0 Emissions

5.1. General

Emissions calculations are divided into "permitted" and "exempt" categories. APCD Rule 202 lists what equipment is exempt from permit. 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 HAP emissions from the POPCO facility. Section 5.6 provides the estimated emissions from permit exempt. Section 5.7 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) [c]
- Reactive Organic Compounds (ROC)
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x) [d]
- Particulate Matter (PM) [e]
- Particulate Matter smaller than 10 microns (PM_{10})

Permitted emissions are calculated for both short term (hourly and daily) and long term (quarterly and annual) time periods. Section 4.0 (Engineering Analysis) provides a general discussion of the basic calculation methodologies and emission factors used. The reference documentation for the specific emission calculations, as well as detailed calculation spreadsheets, may be found in Section 4 and Attachment 10.1. Table 5.1 provides the basic operating characteristics. Table 5.2 provides the specific emission factors. Tables 5.3 and 5.4 show the permitted short-term and permitted long-term emissions for each unit or operation. In these tables, 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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[c] Calculated and reported as nitrogen dioxide (NO_2)
[d] Calculated and reported as sulfur dioxide (SO_2)
[e] 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 for each emission unit are assumed. Table 5.5 shows the total permitted emissions for the facility. Peak quarterly and annual emissions were based on the following, equipment-operating assumptions based on 8760 hrs/yr, and 2190 hrs/qtr, unless otherwise noted:

- 2 Utility boilers operating at maximum rating (41.0 MMBtu/hr).
- One 2.1 MMBtu/hr sulfinol TEG Reboiler.
- Sulfur Recovery/Tail Gas Unit operating at maximum rating (60 – 80 LTD; depending on H_2S levels).
- A 5.62 MMBtu fuel combustion contribution from SRU tailgas incineration to either, or split between both, B-801 A/B boilers.
- Flare pilot and purge volumes operating at maximum rating and 24 ppmv total sulfur content (pilot) and 80 ppmv total sulfur/4 ppmv H_2S (purge); baseline system leakage for the HC flare header and the acid gas flare header.
- Planned flaring pursuant to POPCO's approved Rule 359 Flare Minimization plan, as modified by the AQIA of this event documented in ATC 9047 and ATC 9047-01 to not exceed 0.757 MMSCF/hr and 18.20 MMSCFD of sales gas quality gas (1190 Btu/SCF, HHV basis). Long term planned flaring pursuant to POPCO's approved Rule 359 Flare Minimization plan not exceeding 18.20 MMSCF/month of sales gas quality gas (1190 Btu/SCF, HHV basis).
- Stretford Oxidizer Tank emissions of 0.10 lb/hr.
- Methanol tank operations at permitted throughputs.
- 2 Wastewater Tanks
- Emergency/Standby Diesel-Fired Engine
- Emergency Electrical Generator – Instrument Air

5.4 *Part 70: Federal Potential to Emit for the Facility*

Table 5.6 lists the federal Part 70 potential to emit. Being a NSR source, all project emissions, except fugitive emissions that are not subject to any applicable NSPS or NESHAP requirement are counted in the federal definition of potential to emit. For the POPCO facility, fugitives from equipment subject to NSPS KKK and LLL are included in the federal PTE. Since this entire facility is a Gas Processing Plant subject to the above NSPS, the fugitives are included in the federal PTE calculations.

5.5 *Part 70: Hazardous Air Pollutant Emissions for the Facility*

Total emissions of hazardous air pollutants (HAP) are computed for informational purposes only. HAP emission factors are shown in Table 5.8. Potential annual HAP emissions, based on the worst-case scenario listed in Section 5.3 above, are shown in Table 5.9.

5.6 *Exempt Emission Sources/Part 70 Insignificant Emissions*

Equipment/activities exempt pursuant to Rule 202 include maintenance operations involving surface coating. Insignificant emission units are defined under APCD Rule 1301 as any regulated air pollutant emitted from the unit, excluding HAPs, that are less than 2 tons per year based on the unit's potential to emit and any HAP regulated under section 112(g) of the Clean

Air Act that does not exceed 0.5 ton per year based on the unit's potential to emit. The following emission units are exempt from permit per Rule 202, but are not considered insignificant emission units, since these exceed the insignificant emissions threshold.

Table 5.9 presents the estimated annual emissions from these exempt equipment items, including those exempt items not considered insignificant. This permit includes the Solvents/Surface coating activities during maintenance operations. The basis for these calculations is presented in Table 10.1.

5.7 Net Emissions Increase Calculation

The net emissions increase (NEI) for POPCO is equal to the existing facility NEI plus any emissions increase ("I") due to past projects. This facility's contribution to the stationary source's net emissions increase since November 15, 1990 (the day the federal Clean Air Act Amendments were adopted) is based on the NSR permit actions since December 5, 1991, is as stated in Table 5.10. The NEI for the Exxon – SYU stationary sources is found in Table 10.2.

Table 5.1 Operating Equipment Description

Equipment Item / Description	APCD ID#	Fuel	HHV	ppmv S	Size	Units	Capacity	Units	hr	day	qtr	year
		Device Specifications					**Usage Data**		**Maximum Operating Schedule**			
Utility Boiler												
Boiler B-801 A	2350	PG	1467	24	41.00	MMBtu/hr	41.00	MMBtu/hr	1	24	2,190	8,760
Boiler B-801 B	2351	PG	1467	24	41.00	MMBtu/hr	41.00	MMBtu/hr	1	24	2,190	8,760
Stretford Tailgas Incineration												
Boiler B-801 A and/or B-801 B		TGU	--	--	5.62	MMBtu/hr	5.62	MMBtu/hr	1	24	2,190	8,760
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank												
Boiler B-801 A and/or B-801 B		TGU	--	100	99.9	% H_2S Reduction	60.00	LT/D H_2S	1	24	2,190	8,760
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring												
Pilot Gas	102614	PG	1190	24	2000	scf/hr	2.38	MMBtu/hr	1	24	2,190	8,760
Purge Gas	102614	PG	1190	80	200	scf/hr	0.24	MMBtu/hr	1	24	2,190	8,760
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring												
AG Header - Compressor Seal Leakage	102615	PG	1190	239	311	scf/hr	0.37	MMBtu/hr	1	24	2,190	8,760
HC/AG Headers - Baseline System Leakage	102615	PG	1190	239	600	scf/hr	0.71	MMBtu/hr	1	24	2,190	8,760
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring												
Startups and Maintenance	102616	PG	1190	24	0.76	MMSCF/hr	900.93	MMBtu/hr	1	24	43	172
Tailgas Incineration in ZTOF	108094	TGU	--	--	5.62	MMBtu/hr	5.62	MMBtu/hr	1	8	16	64
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring												
Miscellaneous	108095	PG	1190	239	0.3	MMSCF/hr	357.000	MMBtu/hr	1	2.5	2.5	5
SRU Failure	102617	Acid Gas	1114	41,640	1480	scf/event	1.65	MMBtu/event	0.008	0.008	0.008	0.008
Sulfinol TEG Reboiler	2352	PUC Gas	1050	80	2.10	MMBtu/hr	2.10	MMBtu/hr	1	24	2,190	8,760

Equipment Item	Description		Device Specifications					Usage Data		Maximum Operating Schedule			
		APCD ID#	Fuel	HHV	ppmv	Size	Units	Capacity	Units	hr	day	qtr	year
Fugitive Components – Gas/Light Liquid Service													
	Valves - Unsafe	7070	--	--	--	32	clp	--	--	1	24	2,190	8,760
	Valves - Bellows / Background ppmv	7066	--	--	--	631	clp	--	--	1	24	2,190	8,760
	Valves - Category B	7068	--	--	--	1,902	clp	--	--	1	24	2,190	8,760
	Valves - Category C	106397	--	--	--	434	clp	--	--	1	24	2,190	8,760
	Valves - Category F	9712	--	--	--	232	clp	--	--	1	24	2,190	8,760
	Valves - Category J	7067	--	--	--	1,100	clp	--	--	1	24	2,190	8,760
	Flanges/Connections - Accessible/Inaccessible	7071	--	--	--	7,168	clp	--	--	1	24	2,190	8,760
	Flanges/Connections - Unsafe	7074	--	--	--	615	clp	--	--	1	24	2,190	8,760
	Flanges/Connections - Category B	7072	--	--	--	4,367	clp	--	--	1	24	2,190	8,760
	Flanges/Connections - Category C	7073	--	--	--	1,875	clp	--	--	1	24	2,190	8,760
	Compressor Seals - To VRS	7079	--	--	--	6	clp	--	--	1	24	2,190	8,760
	PSV - To Atm/Flare	7075	--	--	--	154	clp	--	--	1	24	2,190	8,760
	Pump Seals - Single	7081	--	--	--	2	clp	--	--	1	24	2,190	8,760
	Pump Seals - Dual/Tandem	7080	--	--	--	10	clp	--	--	1	24	2,190	8,760
	Total Components:					18,528	clp						
Tanks													
	Methanol Tank (T-111)	102620	--	--	--	10,500	gallons	1.9	psia	1	1	1	1
	Wastewater Tank (T-601)	103103	--	--	--	92,000	gallons			1	24	2,190	8,760
	Wastewater Tank (T-807)	103104	--	--	--	36,700	gallons			1	24	2,190	8,760
Internal Combustion Engines													
	FW Pump A	2359	D2	140,000	15	420	bhp	3.23	MMBtu/hr	1	2	NA	NA
	FW Pump B	2356	D2	140,000	15	420	bhp	3.23	MMBtu/hr	1	2	NA	NA
	Emergency Electrical Generator	2358	D2	140,000	15	52	bhp	0.40	MMBtu/hr	1	2	20	20
	Emergency Electrical Generator Instr Air	2357	D2	140,000	15	111	bhp	0.85	MMBtu/hr	1	2	20	20
Solvent Usage													
	Cleaning/Degreasing	8662	--	--	--	various	lb/gal	various	lb/gal	1	24	2,190	8,760

Table 5.2 Equipment Emission Factors

Equipment Item	Description	APCD ID#	NOx	ROC	CO	SOx	PM	PM10	Units
Utility Boiler									
	Boiler B-801 A	2350	0.036	0.00098	0.073	0.0028	0.00898	0.00853	lb/MMBtu
	Boiler B-801 B	2351	0.036	0.00098	0.073	0.0028	0.00898	0.00853	lb/MMBtu
Stretford Tailgas Incineration									
	Boiler B-801 A and/or B-801 B		0.036	0.00098	0.073	See SRU Below	0.00898	0.00853	lb/MMBtu
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank									
	Boiler B-801 A and/or B-801 B			0.1		5.44			lb/hr
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring									
	Pilot Gas	102614	0.017	0.126	0.012	0.0034	0.0001	0.0001	lb/MMBtu
	Purge Gas	102614	0.017	0.126	0.012	0.0114	0.0001	0.0001	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring									
	AG Header - Compressor Seal Leakage	102615	0.118	0.126	0.012	0.0339	0.0001	0.0001	lb/MMBtu
	HC/AG Headers - Baseline System Leakage	102615	0.118	0.126	0.012	0.0339	0.0001	0.0001	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring									
	Startups and Maintenance	102616	0.200	0.13	0.36	0.0034	0.014	0.014	lb/MMBtu
	Tailgas Incineration in ZTOF	108094	0.200	0.13	0.36	See SRU	0.014	0.014	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring									
	Miscellaneous	108095	0.200	0.13	0.36	0.0339	0.014	0.014	lb/MMBtu
	SRU Failure	102617	0.200	0.13	0.36	6.3170	0.014	0.014	lb/MMBtu
Sulfinol TEG Reboiler		2352	0.098	0.0054	0.082	0.0129	0.0075	0.0075	lb/MMBtu

Equipment Item	Description	APCD ID#	NOx	ROC	CO	SOx	PM	PM10	Units
Fugitive Components – Gas/Light Liquid Service									
	Valves - Unsafe	7070	--	0.4020	--	--	--	--	lb/day-clp
	Valves - Bellows / Background ppmv	7066	--	0.0000	--	--	--	--	lb/day-clp
	Valves - Category B	7068	--	0.0603	--	--	--	--	lb/day-clp
	Valves - Category C	106397	--	0.0523	--	--	--	--	lb/day-clp
	Valves - Category F	9712	--	0.0402	--	--	--	--	lb/day-clp
	Valves - Category J	7067	--	0.0402	--	--	--	--	lb/day-clp
	Flanges/Connections - Accessible/Inaccessible	7071	--	0.0050	--	--	--	--	lb/day-clp
	Flanges/Connections - Unsafe	7074	--	0.0249	--	--	--	--	lb/day-clp
	Flanges/Connections - Category B	7072	--	0.0037	--	--	--	--	lb/day-clp
	Flanges/Connections - Category C	7073	--	0.0032	--	--	--	--	lb/day-clp
	Compressor Seals - To VRS	7079	--	0.0000	--	--	--	--	lb/day-clp
	PSV - To Atm/Flare	7075	--	0.1393	--	--	--	--	lb/day-clp
	Pump Seals - Single	7081	--	0.1862	--	--	--	--	lb/day-clp
	Pump Seals - Dual/Tandem	7080	--	0.0221	--	--	--	--	lb/day-clp
	Total Components:								
Tanks									
	Methanol Tank (T-111)	102620		1.41					lb/1000 gal
	Wastewater Tank (T-601)	103103		0.018					lb/ft^2 day
	Wastewater Tank (T-807)	103104		0.018					lb/ft^2 day
Internal Combustion Engines									
	FW Pump A	2359	--	--	--	--	--	--	
	FW Pump B	2356	--	--	--	--	--	--	
	Emergency Electrical Generator	2358	14.061	1.12	3.03	0.006	1.0	1.0	g/bhp-hr
	Emergency Electrical Generator Instr Air	2357	14.061	1.12	3.03	0.006	1.0	1.0	g/bhp-hr
Solvent Usage									
	Cleaning/Degreasing	8662		mass balance					lbs

Table 5.3 Hourly and Daily Emissions

Equipment Item	Description		NOx		ROC		CO		SOx		PM		PM10		Federal
		APCD ID#	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	lb/hr	lb/day	Enforceability
Utility Boiler															
	Boiler B-801 A	2350	1.48	35.42	0.04	0.96	2.99	71.83	0.11	2.72	0.37	8.84	0.35	8.39	FE
	Boiler B-801 B	2351	1.48	35.42	0.04	0.96	2.99	71.83	0.11	2.72	0.37	8.84	0.35	8.39	FE
Stretford Tailgas Incineration															
	Tailgas Emissions to B-801A or B-801B		0.20	4.86	0.01	0.13	0.41	9.85	See SRU Below		0.05	1.21	0.05	1.15	FE
	Emission Limits for B-801A and B-801B Combined		3.15	75.70											
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank															
	Tailgas Emissions to B-801A or B-801B				0.10	2.40			5.44	130.54					FE
	Emission Limits for B-801A and B-801B Combined								5.67	135.98					
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring															
	Pilot Gas	102614	0.04	0.97	0.30	7.20	0.03	0.69	0.01	0.19	0.00	0.01	0.00	0.01	FE
	Purge Gas	102614	0.00	0.10	0.03	0.72	0.00	0.07	0.00	0.06	0.00	0.00	0.00	0.00	FE
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring															
	AG Header - Compressor Seal Leakage	102615	0.04	1.05	0.05	1.12	0.00	0.11	0.01	0.30	0.00	0.00	0.00	0.00	FE
	HC/AG Headers - Baseline System Leakage	102615	0.08	2.02	0.09	2.16	0.01	0.21	0.02	0.58	0.00	0.00	0.00	0.00	FE
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring															
	Startups and Maintenance	102616	180.19	4324.44	117.12	2810.89	324.33	7783.99	3.07	73.70	12.61	302.71	12.61	302.71	FE
	Tailgas Incineration in ZTOF	108094	1.12	8.99	0.73	5.84	2.02	16.19	See SRU		0.08	0.63	0.08	0.63	FE
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring															
	Miscellaneous	108095	71.40	178.50	46.41	116.03	128.52	321.30	12.12	30.29	5.00	12.50	5.00	12.50	FE
	SRU Failure	102617	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	FE
Sulfinol TEG Reboiler		2352	0.21	4.94	0.01	0.27	0.17	4.13	0.03	0.65	0.02	0.38	0.02	0.38	A

Equipment Item Description	APCD ID#	NOx lb/hr	NOx lb/day	ROC lb/hr	ROC lb/day	CO lb/hr	CO lb/day	SOx lb/hr	SOx lb/day	PM lb/hr	PM lb/day	PM10 lb/hr	PM10 lb/day	Federal Enforceability
Fugitive Components – Gas/Light Liquid Service														
Valves - Unsafe	7070	--	--	0.54	12.87	--	--	--	--	--	--	--	--	NE
Valves - Bellows / Background ppmv	7066	--	--	0.00	0.00	--	--	--	--	--	--	--	--	NE
Valves - Category B	7068	--	--	4.78	114.70	--	--	--	--	--	--	--	--	NE
Valves - Category C	106397	--	--	0.95	22.68	--	--	--	--	--	--	--	--	NE
Valves - Category F	9712	--	--	0.39	9.33	--	--	--	--	--	--	--	--	NE
Valves - Category J	7067	--	--	1.84	44.22	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Accessible/Inaccessible	7071	--	--	1.49	35.75	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Unsafe	7074	--	--	0.64	15.34	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Category B	7072	--	--	0.68	16.34	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Category C	7073	--	--	0.25	6.08	--	--	--	--	--	--	--	--	NE
Compressor Seals - To VRS	7079	--	--	0.00	0.00	--	--	--	--	--	--	--	--	NE
PSV - To Atm/Flare	7075	--	--	0.89	21.45	--	--	--	--	--	--	--	--	NE
Pump Seals - Single	7081	--	--	0.02	0.37	--	--	--	--	--	--	--	--	NE
Pump Seals - Dual/Tandem	7080	--	--	0.01	0.22	--	--	--	--	--	--	--	--	NE
Sub-Total:				**12.47**	**299.35**									**FE**
Tanks														
Methanol Tank (T-111)	102620			14.82	14.82									A
Wastewater Tank (T-601)	103103			0.06	1.33									A
Wastewater Tank (T-807)	103104			0.01	0.21									A
Internal Combustion Engines														
FW Pump A	2359	--	--	--	--	--	--	--	--	--	--	--	--	
FW Pump B	2356	--	--	--	--	--	--	--	--	--	--	--	--	
Emergency Electrical Generator	2358	1.61	3.22	0.13	0.26	0.35	0.69	0.00	0.00	0.11	0.23	0.11	0.23	A
Emergency Electrical Generator Instr Air	2357	3.44	6.88	0.27	0.55	0.74	1.48	0.00	0.00	0.24	0.49	0.24	0.49	A
Solvent Usage														
Cleaning/Degreasing	8662			0.05	1.10									FE

Table 5.4 Quarterly and Annual Emissions

Equipment Item	Description		NOx		ROC		CO		SOx		PM		PM10		Federal
		APCD ID#	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	TPQ	TPY	Enforceability
Utility Boiler															
	Boiler B-801 A	2350	1.62	6.46	0.04	0.18	3.28	13.11	0.12	0.50	0.40	1.61	0.38	1.53	FE
	Boiler B-801 B	2351	1.62	6.46	0.04	0.18	3.28	13.11	0.12	0.50	0.40	1.61	0.38	1.53	FE
Stretford Tailgas Incineration															
	Tailgas Emissions to B-801A or B-801B		0.22	0.89	0.01	0.02	0.45	1.80	See SRU Below		0.06	0.22	0.05	0.21	FE
	Emission Limits for B-801A and B-801B Combined		3.45	13.82											
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank															
	Tailgas Emissions to B-801A or B-801B				0.11	0.44			5.96	23.82					FE
	Emission Limits for B-801A and B-801B Combined								6.20	24.82					
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring															
	Pilot Gas	102614	0.04	0.18	0.33	1.31	0.03	0.13	0.01	0.04	0.00	0.00	0.00	0.00	FE
	Purge Gas	102614	0.00	0.02	0.03	0.13	0.00	0.01	0.00	0.01	0.00	0.00	0.00	0.00	FE
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring															
	AG Header - Compressor Seal Leakage	102615	0.05	0.19	0.05	0.20	0.00	0.02	0.01	0.06	0.00	0.00	0.00	0.00	FE
	HC/AG Headers - Baseline System Leakage	102615	0.09	0.37	0.10	0.39	0.01	0.04	0.03	0.11	0.00	0.00	0.00	0.00	FE
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring															
	Startups and Maintenance	102616	3.87	15.50	2.52	10.07	6.97	27.89	0.07	0.26	0.27	1.08	0.27	1.08	FE
	Tailgas Incineration in ZTOF	108094	0.01	0.04	0.01	0.02	0.02	0.06	See SRU		0.00	0.00	0.00	0.00	FE
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring															
	Miscellaneous	108095	0.09	0.18	0.06	0.12	0.16	0.32	0.02	0.03	0.01	0.01	0.01	0.01	FE
	SRU Failure	102617	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	FE
Sulfinol TEG Reboiler		2352	0.23	0.90	0.01	0.05	0.19	0.75	0.03	0.12	0.02	0.07	0.02	0.07	A

Equipment Item / Description	APCD ID#	NOx TPQ	NOx TPY	ROC TPQ	ROC TPY	CO TPQ	CO TPY	SOx TPQ	SOx TPY	PM TPQ	PM TPY	PM10 TPQ	PM10 TPY	Federal Enforceability
Fugitive Components – Gas/Light Liquid Service														
Valves - Unsafe	7070	--	--	0.59	2.35	--	--	--	--	--	--	--	--	NE
Valves - Bellows / Background ppmv	7066	--	--	0.00	0.00	--	--	--	--	--	--	--	--	NE
Valves - Category B	7068	--	--	5.23	20.93	--	--	--	--	--	--	--	--	NE
Valves - Category C	106397	--	--	1.03	4.14	--	--	--	--	--	--	--	--	NE
Valves - Category F	9712	--	--	0.43	1.70	--	--	--	--	--	--	--	--	NE
Valves - Category J	7067	--	--	2.02	8.07	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Accessible/Inaccessible	7071	--	--	1.63	6.53	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Unsafe	7074	--	--	0.70	2.80	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Category B	7072	--	--	0.75	2.98	--	--	--	--	--	--	--	--	NE
Flanges/Connections - Category C	7073	--	--	0.28	1.11	--	--	--	--	--	--	--	--	NE
Compressor Seals - To VRS	7079	--	--	0.00	0.00	--	--	--	--	--	--	--	--	NE
PSV - To Atm/Flare	7075	--	--	0.98	3.91	--	--	--	--	--	--	--	--	NE
Pump Seals - Single	7081	--	--	0.02	0.07	--	--	--	--	--	--	--	--	NE
Pump Seals - Dual/Tandem	7080	--	--	0.01	0.04	--	--	--	--	--	--	--	--	NE
Sub-Total:				**13.66**	**54.63**									**FE**
Tanks														
Methanol Tank (T-111)	102620			0.01	0.01									A
Wastewater Tank (T-601)	103103			0.06	0.24									A
Wastewater Tank (T-807)	103104			0.01	0.04									A
Internal Combustion Engines														
FW Pump A	2359	--	--	--	--	--	--	--	--	--	--	--	--	
FW Pump B	2356	--	--	--	--	--	--	--	--	--	--	--	--	
Emergency Electrical Generator	2358	0.02	0.02	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	A
Emergency Electrical Generator Instr Air	2357	0.03	0.03	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	0.01	A
Solvent Usage														
Cleaning/Degreasing	8662			0.05	0.2									FE

Notes

FE = Federally Enforceable

NE = Not Enforceable

A = APCD-Only Enforceable

Table 5.5 Total Permitted Facility Emissions

A. Hourly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	1.48	0.04	2.99	0.11	0.37	0.35
Boiler B-801B	1.48	0.04	2.99	0.11	0.37	0.35
Stretford Tailgas Incineration	0.20	0.01	0.41	SRU Below	0.05	0.05
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.10	0.00	5.44	0.00	0.00
Combined B-801A/B Stack Emissions =	3.15	0.19	6.40	5.67	0.79	0.75
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.04	0.33	0.03	0.01	0.00	0.00
Planned Continuous Flaring	0.13	0.14	0.01	0.04	0.00	0.00
Sulfinol TEG Reboiler	0.21	0.01	0.17	0.03	0.02	0.02
Fugitive Components - Gas	--	12.47	--	--	--	--
Tanks	--	14.88	--	--	--	--
Internal Combustion Engines	5.05	0.40	1.09	0.07	0.36	0.36
Solvent Usage	--	0.05	--	--	--	--
Totals (lb/hr)	**8.59**	**28.47**	**7.70**	**5.81**	**1.16**	**1.12**

B. Daily

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	35.42	0.96	71.83	2.72	8.84	8.39
Boiler B-801B	35.42	0.96	71.83	2.72	8.84	8.39
Stretford Tailgas Incineration	4.86	0.13	9.85	0.00	1.21	1.15
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	2.40	0.00	130.54	0.00	0.00
Combined B-801A/B Stack Emissions =	75.70	4.46	153.51	135.98	18.88	17.94
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	1.07	7.92	0.75	0.26	0.01	0.01
Planned Continuous Flaring	3.07	3.28	0.31	0.88	0.00	0.00
Sulfinol TEG Reboiler	4.94	0.27	4.13	0.65	0.38	0.38
Fugitive Components - Gas	--	299.35	--	--	--	--
Tanks	--	16.36	--	--	--	--
Internal Combustion Engines	10.11	0.80	2.18	0.13	0.72	0.72
Solvent Usage	--	1.10	--	--	--	--
Totals (lb/day)	**94.89**	**333.53**	**160.89**	**137.91**	**19.99**	**19.04**

C. Quarterly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	1.62	0.04	3.28	0.12	0.40	0.38
Boiler B-801B	1.62	0.04	3.28	0.12	0.40	0.38
Stretford Tailgas Incineration	0.22	0.01	0.45	SRU Below	0.06	0.05
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.11	0.00	5.96	0.00	0.00
Combined B-801A/B Stack Emissions =	3.45	0.20	7.00	6.20	0.86	0.82
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.05	0.36	0.03	0.01	0.00	0.00
Planned Continuous Flaring	0.14	0.15	0.01	0.04	0.00	0.00
Planned Other Flaring	3.88	2.52	6.99	0.07	0.27	0.27
Unplanned Other Flaring	0.09	0.06	0.16	0.02	0.01	0.01
Sulfinol TEG Reboiler	0.23	0.01	0.19	0.03	0.02	0.02
Fugitive Components - Gas	--	13.66	--	--	--	--
Tanks	--	0.08	--	--	--	--
Internal Combustion Engines	0.05	0.02	0.02	0.02	0.02	0.02
Solvent Usage	--	0.05	--	--	--	--
Totals (TPQ)	**7.89**	**17.11**	**14.41**	**6.39**	**1.18**	**1.13**

D. Annual

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	6.46	0.18	13.11	0.50	1.61	1.53
Boiler B-801B	6.46	0.18	13.11	0.50	1.61	1.53
Stretford Tailgas Incineration	0.89	0.02	1.80	0.00	0.22	0.21
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.44	0.00	23.82	0.00	0.00
Combined B-801A/B Stack Emissions =	13.82	0.81	28.02	24.82	3.45	3.27
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.19	1.44	0.14	0.05	0.00	0.00
Planned Continuous Flaring	0.56	0.60	0.06	0.16	0.00	0.00
Planned Other Flaring	15.53	10.10	27.96	0.26	1.09	1.09
Unplanned Other Flaring	0.18	0.12	0.32	0.03	0.01	0.01
Sulfinol TEG Reboiler	0.90	0.05	0.75	0.12	0.07	0.07
Fugitive Components - Gas	--	54.63	--	--	--	--
Tanks	--	0.29	--	--	--	--
Internal Combustion Engines	0.05	0.02	0.02	0.02	0.02	0.02
Solvent Usage	--	0.20	--	--	--	--
Totals (TPY)	**31.23**	**68.26**	**57.26**	**25.46**	**4.64**	**4.46**

Table 5.6 Federal Potential to Emit

A. Hourly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	1.48	0.04	2.99	0.11	0.37	0.35
Boiler B-801B	1.48	0.04	2.99	0.11	0.37	0.35
Stretford Tailgas Incineration	0.20	0.01	0.41	SRU Below	0.05	0.05
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.10	0.00	5.44	0.00	0.00
Combined B-801A/B Stack Emissions =	3.15	0.19	6.40	5.67	0.79	0.75
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.04	0.33	0.03	0.01	0.00	0.00
Planned Continuous Flaring	0.13	0.14	0.01	0.04	0.00	0.00
Fugitive Components - Gas	--	12.47	--	--	--	--
Tanks	--	14.88	--	--	--	--
Internal Combustion Engines	5.05	0.40	1.09	0.07	0.36	0.36
Solvent Usage	--	0.05	--	--	--	--
Totals (lb/hr)	**8.38**	**28.46**	**7.53**	**5.78**	**1.15**	**1.11**

B. Daily

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	35.42	0.96	71.83	2.72	8.84	8.39
Boiler B-801B	35.42	0.96	71.83	2.72	8.84	8.39
Stretford Tailgas Incineration	4.86	0.13	9.85	0.00	1.21	1.15
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	2.40	0.00	130.54	0.00	0.00
Combined B-801A/B Stack Emissions =	75.70	4.46	153.51	135.98	18.88	17.94
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	1.07	7.92	0.75	0.26	0.01	0.01
Planned Continuous Flaring	3.07	3.28	0.31	0.88	0.00	0.00
Fugitive Components - Gas	--	299.35	--	--	--	--
Tanks	--	16.36	--	--	--	--
Internal Combustion Engines	10.11	0.80	2.18	0.13	0.72	0.72
Solvent Usage	--	1.10	--	--	--	--
Totals (lb/day)	**89.95**	**333.26**	**156.75**	**137.26**	**19.61**	**18.67**

C. Quarterly

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	1.62	0.04	3.28	0.12	0.40	0.38
Boiler B-801B	1.62	0.04	3.28	0.12	0.40	0.38
Stretford Tailgas Incineration	0.22	0.01	0.45	SRU Below	0.06	0.05
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.11	0.00	5.96	0.00	0.00
Combined B-801A/B Stack Emissions =	3.45	0.20	7.00	6.20	0.86	0.82
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.05	0.36	0.03	0.01	0.00	0.00
Planned Continuous Flaring	0.14	0.15	0.01	0.04	0.00	0.00
Planned Other Flaring	3.88	2.52	6.99	0.07	0.27	0.27
Unplanned Other Flaring	0.09	0.06	0.16	0.02	0.01	0.01
Fugitive Components - Gas	--	13.66	--	--	--	--
Tanks	--	0.08	--	--	--	--
Internal Combustion Engines	0.05	0.02	0.02	0.02	0.02	0.02
Solvent Usage	--	0.05	--	--	--	--
Totals (TPQ)	**7.67**	**17.10**	**14.22**	**6.36**	**1.16**	**1.12**

D. Annual

Equipment Category	NOx	ROC	CO	SOx	PM	PM10
Boiler B-801A	6.46	0.18	13.11	0.50	1.61	1.53
Boiler B-801B	6.46	0.18	13.11	0.50	1.61	1.53
Stretford Tailgas Incineration	0.89	0.02	1.80	0.00	0.22	0.21
SRU-Stretford Tailgas Incineration/ Stretford Oxidizer Tank	0.00	0.44	0.00	23.82	0.00	0.00
Combined B-801A/B Stack Emissions =	13.82	0.81	28.02	24.82	3.45	3.27
John Zink Thermal Oxidizer ("ZTOF")						
Planned Pilot/Purge Flaring	0.19	1.44	0.14	0.05	0.00	0.00
Planned Continuous Flaring	0.56	0.60	0.06	0.16	0.00	0.00
Planned Other Flaring	15.53	10.10	27.96	0.26	1.09	1.09
Unplanned Other Flaring	0.18	0.12	0.32	0.03	0.01	0.01
Fugitive Components - Gas	--	54.63	--	--	--	--
Tanks	--	0.29	--	--	--	--
Internal Combustion Engines	0.05	0.02	0.02	0.02	0.02	0.02
Solvent Usage	--	0.20	--	--	--	--
Totals (TPY)	**30.33**	**68.21**	**56.51**	**25.34**	**4.57**	**4.39**

Table 5.7 HAP Emission Factors

Equipment Item	Description	APCD ID#	Benzene	Toluene	Xylene	Formaldehyde	PAH	Hexane	Iso-Octane	Units
Utility Boiler[a]										
	Boiler B-801 A	2350	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
	Boiler B-801 B	2351	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
Stretford Tailgas Incineration[b]										
	Boiler B-801 A and/or B-801 B		2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank										
	Boiler B-801 A and/or B-801 B									
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring[c]										
	Pilot Gas	102614	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
	Purge Gas	102614	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring[c]										
	AG Header - Compressor Seal Leakage	102615	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
	HC/AG Headers - Baseline System Leakage	102615	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring[c]										
	Startups and Maintenance	102616	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
	Tailgas Incineration in ZTOF	108094	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring[c]										
	Miscellaneous	108095	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
	SRU Failure	102617	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu
Sulfinol TEG Reboiler[a]		2352	2.06E-06	3.33E-06	--	7.35E-05	8.65E-08	1.76E-03	--	lb/MMBtu

Equipment Item		Emission Factors							
	APCD ID#	Benzene	Toluene	Xylene	Formaldehyde	PAH	Hexane	Iso-Octane	Units
Fugitive Components – Gas/Light Liquid Service[d]									
Valves - Unsafe	7070	0.013					0.068	0.060	lb/day-clp
Valves - Bellows / Background ppmv	7066	0.000					0.000	0.000	lb/day-clp
Valves - Category B	7068	0.002					0.010	0.009	lb/day-clp
Valves - Category C	106397	0.002					0.009	0.008	lb/day-clp
Valves - Category F	9712	0.001					0.007	0.006	lb/day-clp
Valves - Category J	7067	0.001					0.007	0.006	lb/day-clp
Flanges/Connections - Accessible/Inaccessible	7071	0.000					0.001	0.001	lb/day-clp
Flanges/Connections - Unsafe	7074	0.001					0.004	0.004	lb/day-clp
Flanges/Connections - Category B	7072	0.000					0.001	0.001	lb/day-clp
Flanges/Connections - Category C	7073	0.000					0.001	0.000	lb/day-clp
Compressor Seals - To VRS	7079	0.000					0.000	0.000	lb/day-clp
PSV - To Atm/Flare	7075	0.004					0.024	0.021	lb/day-clp
Pump Seals - Single	7081	0.006					0.031	0.028	lb/day-clp
Pump Seals - Dual/Tandem	7080	0.001					0.004	0.003	lb/day-clp
Total Components:									
Tanks[e]									
Methanol Tank (T-111)	102620								
Wastewater Tank (T-601)	103103	0.0011					0.0896		lb/lb ROC
Wastewater Tank (T-807)	103104	0.0011					0.0896		lb/lb ROC
Solvent Usage[f]									
Cleaning/Degreasing	8662	0.05	0.05	0.05					wt fraction

Notes:

[a]Emission Factors for External Combustion Equipment per USEPA AP-42. Table 1.4-3 (7/98). Emission factors for Speciated Organic Compounds from Natural Gas Combustion

[b]Emission Factors for Stretford Tailgas Incineration per USEPA AP-42. Table 1.4-3 (7/98). Emission factors for Speciated Organic Compounds from Natural Gas Combustion

[c]Emission Factors for Fugitives per CARB. Speciation Manual. Second Edition (9/91). Profile Number 757 - Oil & Gas Production Fugitives - Gas Service.

[d]Emission Factors for Thermal Oxidizer per USEPA AP-42. Table 1.4-3 (7/98). Emission factors for Speciated Organic Compounds from Natural Gas Combustion

[e]Emission Factors for Tanks per EPA SPECIATE Version 4.0 (12/2006). Profile number 296 - Fixed Roof Tank - Crude Oil Production

[f]Emission Factors for Solvents per APCD: Solvents assumed to contain 5% benzene, 5% toluene, and 5% xylene

Table 5.8 HAP Annual Emissions

Equipment Item	Description	APCD ID#	HAP Emissions (tpy) Benzene	Toluene	Xylene	Formaldehyde	PAH	Hexane	Iso-Octane
Utility Boiler									
	Boiler B-801 A	2350	3.70E-04	5.99E-04		1.32E-02	1.55E-05	3.17E-01	
	Boiler B-801 B	2351	3.70E-04	5.99E-04		1.32E-02	1.55E-05	3.17E-01	
Stretford Tailgas Incineration									
	Boiler B-801 A and/or B-801 B		5.07E-05	8.21E-05		1.81E-03	2.13E-06	4.34E-02	
Sulfur Recovery Unit – Stretford Tailgas Incineration/Stretford Oxidizer Tank									
	Boiler B-801 A and/or B-801 B								
John Zink Thermal Oxidizer ("ZTOF") – Planned Pilot/Purge Flaring									
	Pilot Gas	102614	2.15E-05	3.47E-05		7.67E-04	9.01E-07	1.84E-02	
	Purge Gas	102614	2.15E-06	3.47E-06		7.67E-05	9.01E-08	1.84E-03	
John Zink Thermal Oxidizer ("ZTOF") – Planned Continuous Flaring									
	AG Header - Compressor Seal Leakage	102615	3.34E-06	5.40E-06		1.19E-04	1.40E-07	2.86E-03	
	HC/AG Headers - Baseline System Leakage	102615	6.44E-06	1.04E-05		2.30E-04	2.70E-07	5.52E-03	
John Zink Thermal Oxidizer ("ZTOF") – Planned Other Flaring[c]									
	Startups and Maintenance	102616	1.60E-04	2.58E-04		5.70E-03	6.70E-06	1.37E-01	
	Tailgas Incineration in ZTOF	108094	3.70E-07	5.99E-07		1.32E-05	1.56E-08	3.17E-04	
John Zink Thermal Oxidizer ("ZTOF") – Unplanned Other Flaring[c]									
	Miscellaneous	108095	1.84E-06	2.98E-06		6.56E-05	7.72E-08	1.58E-03	
	SRU Failure	102617	1.70E-09	2.75E-09		6.06E-08	7.13E-11	1.45E-06	
Sulfinol TEG Reboiler		2352	1.89E-05	3.07E-05		6.76E-04	7.95E-07	1.62E-02	

Equipment Item	Description				HAP Emissions (tpy)			
	APCD ID#	Benzene	Toluene	Xylene	Formaldehyde	PAH	Hexane	Iso-Octane
Fugitive Components – Gas/Light Liquid Service								
Valves - Unsafe	7070	0.08					0.40	0.35
Valves - Bellows / Background ppmv	7066	0.00					0.00	0.00
Valves - Category B	7068	0.67					3.53	3.13
Valves - Category C	106397	0.13					0.70	0.62
Valves - Category F	9712	0.05					0.29	0.25
Valves - Category J	7067	0.26					1.36	1.21
Flanges/Connections - Accessible/Inaccessible	7071	0.21					1.10	0.97
Flanges/Connections - Unsafe	7074	0.09					0.47	0.42
Flanges/Connections - Category B	7072	0.10					0.50	0.45
Flanges/Connections - Category C	7073	0.04					0.19	0.17
Compressor Seals - To VRS	7079	0.00					0.00	0.00
PSV - To Atm/Flare	7075	0.13					0.66	0.58
Pump Seals - Single	7081	0.00					0.01	0.01
Pump Seals - Dual/Tandem	7080	0.00					0.01	0.01
Tanks								
Methanol Tank (T-111)	102620							
Wastewater Tank (T-601)	103103	0.00					0.02	
Wastewater Tank (T-807)	103104	0.00					0.00	
Solvent Usage								
Cleaning/Degreasing	8662	0.01	0.01	0.01				

Table 5.9 Estimated Permit Exempt Emissions

A. Annual

Item	Equipment Category	NOx	ROC	CO	SOx	PM	PM10
	Dust Collector	0.08	0.01	0.02	0.01	0.01	0.01
	Crane (300 ton) #103958	0.07	0.00	0.01	0.01	0.00	0.00
	Crane (35 ton)	0.03	0.00	0.01	0.00	0.00	0.00
	Crane (25 ton)	0.07	0.00	0.02	0.01	0.01	0.01
	Crane (75 ton) #102006	0.04	0.00	0.01	0.00	0.00	0.00
	Pump - N2 #101589	0.26	0.02	0.06	0.03	0.02	0.02
	Crane (200 ton) Hydraulic	0.01	0.00	0.00	0.00	0.00	0.00
	Welder - Lincoln Portable	0.02	0.00	0.01	0.00	0.00	0.00
	Welder - Lincoln Portable	0.02	0.00	0.01	0.00	0.00	0.00
	Manlift - 60 ft	0.01	0.00	0.00	0.00	0.00	0.00
	Manlift - 65 ft	0.01	0.00	0.00	0.00	0.00	0.00
	#1 Light Tower	0.01	0.00	0.00	0.00	0.00	0.00
	Crane (8 ton)	0.01	0.00	0.00	0.00	0.00	0.00
	#2 Light Tower	0.02	0.00	0.00	0.00	0.00	0.00
	#3 Light Tower	0.01	0.00	0.00	0.00	0.00	0.00
	#4 Light Tower	0.26	0.02	0.06	0.03	0.02	0.02
	WaterBlaster (HydroPress)	0.01	0.00	0.00	0.00	0.00	0.00
	CAT 416 C Backhoe	0.02	0.00	0.00	0.00	0.00	0.00
	Air Compressor	0.05	0.00	0.01	0.01	0.00	0.00
	Dust Collector	0.02	0.00	0.00	0.00	0.00	0.00
2353	TEG Reboiler E-121	0.52	0.03	0.43	0.07	0.04	0.04
8792	Forced Air Furnace	0.02	0.00	0.02	0.00	0.00	0.00
	Surface Coating-Maintenance	0.00	0.20	0.00	0.00	0.00	0.00
	Abrasive Blasting	0.00	0.00	0.00	0.00	0.00	0.00
	Totals (TPY):	**1.56**	**0.10**	**0.67**	**0.19**	**0.11**	**0.11**

Previously Exempt: Now subject to Stationary Compression Ignition Engine ATCM							
2356	FW Pump A	1.30	0.09	0.28	0.15	0.09	0.09
2359	FW Pump B	1.30	0.09	0.28	0.15	0.09	0.09
	Emergency Electrical Generator	0.83	0.06	0.18	0.09	0.06	0.06
105147	Emergency Electrical Generator Instr Air	0.34	0.02	0.07	0.04	0.02	0.02

Table 5.10 Facility Net Emissions Increase

I. This Projects "I" NEI-90

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

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

Permit No.	Date Issued	NOx lb/day	NOx ton/yr	ROC lb/day	ROC ton/yr	CO lb/day	CO ton/yr	SOx lb/day	SOx ton/yr	PM lb/day	PM ton/yr	PM10 lb/day	PM10 ton/yr
ATC/PTO 11001	4/1/2003			0.785	0.143								
PTO 8092	9/5/2000	6.98	0.64	21.3	3.85	132.77	22.98	70.22	12.92	1.32	0.08	1.26	0.08
ATC/PTO 12020	8/15/2006	0.00	0.21	0.00	0.14	0.00	0.39	0.00	0.03	0.00	0.02	0.00	0.02
Totals		**6.98**	**0.85**	**22.08**	**4.13**	**132.77**	**23.37**	**70.22**	**12.95**	**1.32**	**0.10**	**1.26**	**0.10**

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

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

Permit No.	Date Issued	NOx lb/day	NOx ton/yr	ROC lb/day	ROC ton/yr	CO lb/day	CO ton/yr	SOx lb/day	SOx ton/yr	PM lb/day	PM ton/yr	PM10 lb/day	PM10 ton/yr
ATC/PTO 11130	4/2/2004			5.76	1.05								
Totals		**0.00**	**0.00**	**5.76**	**1.05**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**	**0.00**

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

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

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

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

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

Term	NOx lb/day	NOx ton/yr	ROC lb/day	ROC ton/yr	CO lb/day	CO ton/yr	SOx lb/day	SOx ton/yr	PM lb/day	PM ton/yr	PM10 lb/day	PM10 ton/yr
Project "I"	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
P1	6.98	0.85	22.08	4.13	132.77	23.37	70.22	12.95	1.32	0.10	1.26	0.10
P2	0.00	0.00	5.76	1.05	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
D	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
FNEI-90	**6.98**	**0.85**	**16.32**	**3.08**	**132.77**	**23.37**	**70.22**	**12.95**	**1.32**	**0.10**	**1.26**	**0.10**

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

6.0 Air Quality Impact Analysis

6.1. Scope of Review

The scope of the Air Quality Impact Analyses ("AQIA") performed for this project involved an AQIA for the routine operational emissions of the facility (for NO_2, SO_2, CO, PM_{10} and ROC), and for two intermittent operational scenarios with significantly much higher "peak" emissions rates than the routine operating scenario (these two scenarios for ROC, SO_2, NO_2, CO and PM). In addition, pursuant to the APCD's PSD Rule, the project's PTE triggered the requirement to perform a Visibility and Soils analysis.

For the routine operations AQIA and the Visibility & Soils Analysis, ATC 9047's analysis refers to and relies on the previous AQIA prepared for the adjacent ExxonMobil SYU Oil and Gas facility in its ATC 5651 (issued 11/19/87). This AQIA was reviewed in June 1994 SEIR prepared for the POPCO expansion project specified in ATC 9047 and was found to be valid for purposes of the analysis.

However, for certain intermittent operation scenarios, previous AQIA were found to be deficient. One of the scenarios, that of planned Startup Flaring, was identified as a worst-case flaring event, but was never adequately modeled in POPCO's 1983 Flaring Analysis. This deficiency was addressed in the ATC 9047 analysis through a new AQIA.

The other intermittent operation scenario evaluated by a new AQIA was for the impact associated with a SRU failure and the flaring of its acid gas feed. Again, the previous POPCO *1983 Flaring Analysis* AQIA for this scenario was deficient in that it only considered the SO_2 emissions generated by one of two SRUs failing at one time. Because POPCO is no longer proposed the installation of two SRUs, but only one with the acid gas throughput of two units, a new AQIA was required for this scenario. In fact, pursuant to FDP Condition E-5, this analysis was required such that a mitigation system could be identified and verified to prevent any potential violation of the SO_2 ambient air quality standard. The results of this new AQIA element, and an evaluation of the proposed mitigation of this scenario's SO_2 emissions are further summarized below.

6.2. Compliance with Ambient Air Quality Standards

6.2.1 Construction Emissions: In the expansion project SEIR (93-DPF-015rv), it was concluded that emissions associated with construction activities related to installation of the expansion equipment were not required to be quantitatively assessed for ambient air quality impacts because they were estimated to be much less than 25 tons/year of any criteria pollutant (i.e., NO_x, SO_x, CO, ROC, and PM_{10}).

Construction emissions were still required to be mitigated however, through lead agency permit (93-FDP-015) condition E-3 - *Construction Plan*. This plan specified construction dust, and construction internal combustion engine related mitigations to reduce NO_x, CO, SO_x and PM_{10} emissions.

6.2.2 Routine Operations: Impacts from the routine operations of the expanded POPCO Gas Plant were modeled for the criteria pollutants NO_2, SO_2, CO and PM_{10} using the Complex II Model following the procedures specified in the APCD's Authority to Construct Permit Processing

Manual. In addition, a health risk assessment of the project ROC impacts was completed. A summary of the routine operational AQIA results and ROC health risk assessments follows:

ROC HEALTH RISK ASSESSMENT

The ISC Model was used to predict ROC pollutant impacts from the expanded facility's ROC emissions as estimated during the SEIR review. Based on the maximum-hour scenario, an ISC model was used to simulate the maximum ambient concentration of this pollutant. ISC was found by the APCD to produce comparable results to those generated by Complex II with significant lower computer time requirements.

Subsequent to implementation of BARCT and BACT controls for existing and expansion related fugitive emission sources (i.e., valves, flanges and connections) pursuant to the requirements of ATC 9047, the expanded facility project ROC emissions was estimated to be some 34.40 tons less than previously permitted for the entire facility through PTO 8092. This also implied the impact of the ROC pollutant as analyzed in the SEIR had also been reduced. In the SEIR, the ROC and associated air toxics emissions profile from this project were classified as "...adverse but insignificant...", because no adverse chronic hazard (i.e., cancer exposure risk) or acute exposure risks were identified. This conclusion remains unchanged as a result of the revised project's lower ROC emissions.

NO_2, SO_2, CO AND PM CRITERIA POLLUTANT AQIA

Besides ROC, the following pollutants were reanalyzed in the SEIR for the proposed expansion:

- Nitrogen Oxides (NO_x), as NO_2
- Carbon Monoxide (CO)
- Sulfur Oxides (SO_x), as SO_2
- Particulate Matter (PM_{10}) less than 10 microns in diameter

The modeling results as documented in the project expansion SEIR (93-DPF-015rv) for the proposed project operations are shown in Table 6.1. Since the SEIR's review of these results, two other significant changes besides ROC emissions have occurred to the routine operational emissions scenario. Project NO_x emissions have significantly dropped by 5.70 lb/hr and 24.95 tpy because of APCD Rule 342 implementation and compliance by POPCO. However project CO emissions have increased by 5.38 lb/hr and 23.56 tpy because of Rule 342 permitting activities. These changes have been reflected in the results shown in Table 6.1 for project specific impacts and Table 6.2 for the cumulative impacts in the Las Flores Canyon area consolidated oil and gas operating area. The project contribution of PM_{10} will add to the existing background levels that exceeded the state 24-hour average standard. No other violations of the ambient air quality standards were projected for normal operations of the expanded gas plant.

6.2.3 Startup and Maintenance Flaring Analysis: Startup and planned maintenance flaring is an activity that is under the control of POPCO. Thus, any AQIA analysis result of this activity that indicates it would cause a violation of an ambient air quality standard would have compelled the APCD to deny ATC 9047, unless the activity's emissions were mitigated to eliminate the predicted violation(s). In accordance with APCD- modeling rules, the worst case Startup and Maintenance flaring scenario was modeled to demonstrate to the satisfaction of the APCO that these emission scenarios will cause no ambient air quality standard or increment to be exceeded.

The flaring rate is specified in 1997 version of PTO 8092, Condition No. 4.D.5 as 1.514 MMSCF/hr, and is further defined in the POPCO 1983 Flaring Analysis to occur for up to 12 hours in length. Table 6.3 summarizes the results of the pollutant emissions impact of this flaring event in addition to the routine operational emissions of this project and the adjacent ExxonMobil SYU facility. As is shown in this table, flaring at the rate permitted in the 1997 version of PTO 8092 results in an exceedance of the state and federal NO_2 ambient air quality standard outside of the POPCO facility boundary.

As a result, ATC 9047 permit was conditioned to limit the Startup flaring rate to no more than 50 percent of that which was assessed in the AQIA of this event (i.e., 0.757 MMSCF/hr of 1,190 Btu/SCF gas; or a 900.9 MMBtu/hr flaring rate). By POPCO limiting Startup Flaring to the specified rate in ATC 9047 (see Section 9.C), it is estimated this activity will not violate any ambient air quality standard.

6.2.4 SRU Failure Flaring & Mitigation: Failure of the modified SRU unit (operating at 60 LTD) and associated unmitigated acid gas flaring at a rate of 2,162 g/sec of SO_2 from the ZTOF is projected to exceed the state 1-hour SO2 standard if flaring were to last longer than 28 seconds. The state 3-hour SO_2 standard would also be exceeded if flaring lasted longer than 342 seconds. The results of the AQIA performed for this unmitigated "worst-case" SRU failure-flaring scenario are shown in Table 6.4.

POPCO proposed a revised SRU shutdown system, which they assert will prevent any excess flaring of acid gas beyond 28 seconds in duration to the ZTOF from an unexpected SRU shutdown, such that no violation of any applicable SO_2 hourly ambient air quality standard should occur. The equipment required to effect this SRU shutdown system and its performance are required as a condition of this permit.

6.3. Air Quality Increment Analysis

An increment consumption analysis was performed for the combined ExxonMobil Las Flores Canyon SYU and POPCO expansion projects for the pollutants NO_2, PM, PM_{10}, CO, SO_2 and ROC, as documented in the ExxonMobil SYU ATC No. 5651, section 6.2, and Table 6-20. The same modeling methodology was used in this increment analysis as was employed for the standards compliance analyses Section 6.2.2 of ATC 9047. All pollutant increases from the POPCO expansion project were covered in the ExxonMobil ATC increment analysis of ATC No. 5651. The results of the routine operations increment analysis are shown in Table 6.5. During routine facility operations the maximum increment consumption of SO_2, PM, or CO from the expanded gas facility was not anticipated to exceed any allowable maximum. Some additional background on the scope and validity of this previous increment analysis follows.

In the increment analysis of the ExxonMobil SYU ATC No. 5651, it identified existing sources that would consume increment within the general vicinity of the project site. Increment consuming sources include major stationary sources (per 40 CFR 52.21) constructed since January 6, 1975, and all sources constructed, modified or otherwise permitted to increase emissions after either August 8, 1978 (for SO_2 and PM) or January 1, 1984 (for CO). The only increment consumers identified in the project area, in addition to the proposed POPCO project, were Exxon's SYU Oil and Gas Plant, and Platforms Harmony, Heritage and Heather, which were approved for installation by the US Minerals Management Service.

INCREMENT FEES

Increment fees were triggered for ROC as a result of the expansion permitted through ATC 9047-2. ExxonMobil completed payment of the increment fees in 2007.

6.4. Vegetation and Soils Analysis

Because the modifications of ATC 9047 proposed to decrease ROC (an ozone precursor), but increase the project's SO_x emissions, this analysis was required pursuant to Rule 205.C. This portion of the AQIA section of ATC 9047 relies primarily on the similar analysis performed as part of the issuance of ExxonMobil's SYU oil and gas processing facility ATC No. 5651 on November 19, 1987. The basis of this updated analysis, background concentrations of affected pollutants, and the estimated impacts of both the ExxonMobil and the expanded POPCO facility's routine operations emissions were presumed to be accurately presented and analyzed by the previous analysis. A synopsis of the Vegetation and Soils Analysis considering the modified and expanded POPCO project follows.

The land in the general area of the proposed project is used for grazing. At sufficient concentration and duration, ambient air pollutants, specifically ozone, sulfur dioxide, nitrogen dioxide, and various combinations of the three, can injure vegetation. An ozone concentration of 0.25 ppmv over a six-hour period has been shown to injure plants. Additional studies have also demonstrated slight injury to sensitive plants at ozone exposure levels of 0.02-0.03 ppmv for an 8-hour duration and 0.08-0.15 ppmv for 2 hours. Evidence of minimal foliar injury to trees and shrubs at ozone concentrations of 0.2-0.5 ppmv for 1 hour and to agricultural crops at 0.2-0.41 ppmv for one-half hour has also been substantiated.

The maximum hourly ozone concentration expected during operation of the proposed project is projected to be 0.14 ppmv. Based on past studies this concentration may cause slight damage to sensitive plants.

Recent studies of sulfur dioxide exposure show injury thresholds at 0.3 ppmv for 8 hours (for middle-aged plants), at 0.14 ppmv for 15-20 hours (for oat seedlings), and at a 0.007-0.010 ppmv average for the growing season. The maximum hourly ambient concentration of sulfur dioxide expected during operation of the facility would be approximately 0.19 ppmv (523 μg/m3), which is below the thresholds cited by these studies. Therefore, no plant injury is expected from sulfur dioxide.

Nitrogen dioxide sensitivity has been cited in the literature at concentrations of 2.5 ppmv for a 4-hour duration for tomato seedlings and other plants with middle-aged leaves. Leaf symptoms have been observed at 1.6-2.6 ppmv for 2-day exposures and 20 ppmv for 1-hour exposures. The maximum hourly ambient concentration of nitrogen dioxide predicted during the production phase would be 0.42 ppmv (814 μg/m3), which is well below the injury threshold cited. Therefore, no plant injury is expected from nitrogen dioxide emissions.

During the operating phase, total emissions from the POPCO facility are predicted to be 25.35 tons per year of sulfur dioxide and 41.20 tons per year of nitrogen oxides. This is relatively small in comparison to the adjacent ExxonMobil’s facility's peak contribution at 341 and 337 tons per year for these respective pollutants. However, annual deposition of sulfates and nitrates from both these projects' combined operations onto the surrounding soils will be minimal, based on the large project area over which the pollutants are dispersed. In addition, the pronounced alkalinity of the soils will ameliorate the effects of the minor decrease in pH expected from nitrate or sulfate deposition. No long-term buildup of deposition products is expected because of utilization of these compounds by existing vegetation. In addition, the POPCO facility is not anticipated to emit heavy metals or other toxic substances which could damage soils used for crop or forage production. Therefore, no impact on soils was predicted to occur from project emissions.

6.5. Potential to Impact Visibility and Opacity

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

6.6. Public Nuisance

Historically, oil and gas processing facilities handling high sulfur content petroleum and produced gases within the County of Santa Barbara were the subject of numerous public complaints regarding odors and other related public nuisance factors. Based on these experiences it was considered particularly important to evaluate the potential for public nuisance from the proposed facilities. Emissions from the operation phases of the project were reviewed to determine compliance with APCD Rules 205.A and 303. These rules relate to the prevention of public nuisance as required by Section 41700 of the State Health and Safety Code. In addition, an evaluation of this facility's operations in accordance with the requirements of Santa Barbara County's Ordinance No. 2832 which pertains to facilities "...handling sour gas with an H_2S content greater than 825 ppmv..." was also performed. This ordinance requires that a plan exist for detecting and monitoring H_2S emissions, and operating in a manner such that ambient H_2S concentrations do not exceed the limits established by Ordinance 2832 for the protection of public health. This ordinance also speaks to facilities operating "...in the vicinity of any residence or place of public gathering which could affect the safety or well-being of others...”. Places of public gathering in the vicinity of the POPCO gas plant include the Refugio and El Capitan State Beaches.

There is a potential to create a public nuisance due to emissions of reduced sulfur compounds that could occur during POPCO facility operations. Both the high sulfur content of the sour gas feedstock and the natural gas liquids produced are potential sources of the reduced sulfur compounds. Additional sources of reduced sulfur emissions include the amine unit, the sulfur removal unit (SRU), the tail gas unit, the sour gas pipeline and fugitive emissions from gas and NGL handling facilities.

However, the potential release of reduced sulfur and H_2S emissions from routine operations of the POPCO facility is anticipated to be minimized to a great extent because of the following. SRU failures will be controlled by minimizing the quantity of acid gas sent to the flare. This avoids any potential for excess releases of H_2S and other reduced sulfur compounds. Tailgas unit emissions are expected to be controlled through incineration of this stream by the process boilers. Fugitive hydrocarbon and associated reduced sulfur emission sources will be controlled through a combination of BACT, BARCT and compliance with the LDAR activities specified in APCD Rule 331 and this permit.

However, since the human odor threshold for H_2S is very low at 0.00047 ppmv (Ref. SCAQMD EIR Handbook, App. M), it is possible that odors could, at times, be detectable outside the property line. Therefore, due to the potential for odorous emissions from this facility, an odor-monitoring program has been specified since this plant became operational in 1984. The existing Odor monitoring, including reduced sulfur compounds, is summarized in Table 4.16. POPCO is required to implement the APCD-approved Odor Monitoring Plan, as specified in Section 9.C.

6.7. *Ambient Air Quality Monitoring*

The pre-construction monitoring requirements of APCD's NSR rule were not triggered by ATC 9047 because none of the project's Net Emissions Increases since 1979 exceeded 10 lb/hr of any attainment pollutant, or 5 lb/hr of PM, or 3.3 lb/hr, 80 lb/day, or 15 tons per year of PM_{10}. However, the adjacent ExxonMobil SYU oil and gas processing facility project NEI did trigger these requirements. As a result, ExxonMobil has installed sufficient ambient air quality monitoring stations to monitor and verify that consolidated facility operations do not adversely impact ambient air quality.

Table 6.1 Air Quality Impacts – Operations Phase – Project Specific (μg/m^3)

Pollutant	Averaging Time	Project Contribution	Background	Total	Ambient Standard
NO_2	1-hour	0.0	45	45	470
	Annual	4.0	6	10	100
PM_{10}	24-hour	0.3	61	61.3	50
	Annual	0.1	24	24.1	30
CO	1-hour	45.8	2,629	2,675	23,000
	8-hour	13.1	1,966	1,979	10,000
SO_2	1-hour	215.0	133	348	655
	3-hour	172.0	100	272	1,300
	24-hour	26.0	28	54	131
	Annual	6.7	5	11.7	80

NOTES

1. POPCO project specific contribution concentrations are from the 1987 APCD ATC No. 5651 for the ExxonMobil SYU project, *Air Quality Impact Analysis Technical Support Document, Table 2.5-16*, except for the one-hour SO_2 impact which is derived from the 3-hour value. Background concentration is from Table 2.5-5 of the same document and the annual PM_{10} is derived from the 24-hour concentration.

2. Project-specific NO_2 impacts in this table are adjusted downward by 42% from those presented in SEIR which occurred from implementation of NO_2 emission controls pursuant to Rule 342 and PTO 9215.

3. CO impacts are adjusted upward from those presented in the SEIR for the hourly CO emission increase to 6.34 lb/hr from the hourly rate assessed in the project SEIR of 0.97 lb/hr that occurred through implementation of Rule 342 controls and PTO 9215.

Table 6.2 Cumulative Air Quality Impacts in Las Flores Canyon – Operations Phase ($\mu g/m^3$)

Pollutant	Averaging Time	Cumulative Project Contributions	Background	Total	Ambient Standard
NO_2	1-hour	392	45	437	470
	Annual	42	6	48	100
PM_{10}	24-hour	13	61	74	50
	Annual	4	24	26	30
CO	1-hour	10,399 (3)	2,629	13,028	23,000
	8-hour	4,132 (3)	1,966	6,098	10,000
SO_2	1-hour	346	133	479	655
	3-hour	282	100	382	1,300
	24-hour	51	28	79	131
	Annual	15	5	20	80

NOTES

1. Cumulative impacts in the Las Flores Canyon consolidated oil and gas processing area based upon maximum project operational contribution concentrations attributed to the ExxonMobil SYU and POPCO projects. Except for CO, these values are from the 1987 APCD ATC No. 5651 for the ExxonMobil SYU project, *Air Quality Impact Analysis Technical Support Document*, *Table 2.5-15*, except for the one-hour SO_2 impact which is derived from the 3-hour value. Background concentrations are from Table 2.5-5 of the same document and the annual PM_{10} is derived from the 24-hour concentration.

2. Project-specific NO_2 impacts in this table are adjusted downward by 3 $\mu g/m^3$ from those presented in SEIR which occurred from implementation of NO_2 emission controls pursuant to Rule 342 and PTO 9215.

3. CO impacts are adjusted upward from those presented in SEIR (Table5.1-5) for the hourly CO emission increase to 6.34 lb/hr from the hourly rate assessed in the project SEIR of 0.97 lb/hr that occurred through implementation of Rule 342 controls and PTO 9215.

   The change in the POPCO project's CO emissions was conservatively assumed to affect the cumulative Las Flores Canyon CO impacts by 100 percent of POPCO's increase in mass emissions from the original modeled CO emission rate (i.e., by a factor of 6.34/0.97 = 6.57). This assumption represents a reasonable worst case assessment of the cumulative projects' impacts in Las Flores Canyon.

Table 6.3 Flaring Impacts – Startup Activities[5] ($\mu g/m^3$)

Pollutant	Averaging Time	Maximum Air Quality Impacts	Background	Total	Ambient Standard
NO_2 (1)	1-hour	556	49	605	470
PM_{10}	24-hour	26 (3)	48	74	50 (4)
CO (2)	1-hour 8-hour	7,993 3,690	1,181 1,181	9,174 4,871	23,000 10,000

NOTES

1. Calculated using the ozone-limiting method, using the background concentrations of 126 ppbv and 25 ppbv for ozone and NO_2 respectively.

2. Includes impact from assumed simultaneous operations of ExxonMobil's turbine bypass.

3. POPCO sources contributed 12 μg/m3; POPCO flare alone contributed 11$\mu g/m^3$, and the ExxonMobil source contributed 14 $\mu g/m^3$ to this highest concentration.

4. PM_{10} federal standard is 150 $\mu g/m^3$. The state standard is 50 $\mu g/m^3$

5. Impacts associated with POPCO facility startup flaring emission rates of 360.4, 648.7, and 25.23 lb/hr for NO_x as NO_2, CO, and PM_{10} respectively. Compliance with the NO_2 standard is achieved at one-half of these mass emission rates.

6. Results analysis and summary based upon data communicated in APCD memoranda are maintained in the files for ATC 9047.

Table 6.4 Flaring Impacts – SRU Failures[1] (μg/m³)

Pollutant	Averaging Time	Impact @ 30 min/hr Release (In ExxonMobil Property)	Impact @ 30 min/hr Release (Outside of ExxonMobil Property)	Ambient Standard	Maximum Flare Release Duration for No AAQS Violation (2) (Seconds)
SO_2	1-hour	36,924	33,037	655	28
	3-hour	19,940	17,555	1,300	342

NOTES

1. All data presented here is for impact modeling of Scenario 1, representing the worst-case SRU acid gas feed rate, and thus flaring rate, as reviewed and analyzed by APCD staff. See attachment 10.5. Modeling was performed for POPCO by their contractor, consistent with APCD-approved modeling protocols.

2. Flaring event durations which will not cause violation of standard are revised slightly downwards in accordance with findings of ATC 9047.

Table 6.5 Maximum Project Increment Consumed ($\mu g/m^3$)

Pollutant	Averaging Time	Project Contribution	Increment Consumed to Date (1996)[1]	Total	Allowable Increment
SO_2	3-hour 24-hour Annual	172.0 26.0 6.7	105.0 19.0 5.6	277.0 45.0 12.3	512 91 20
PM	24-hour Annual	0.6 0.1	13.5 3.0	14.1 3.1	37 19
CO[2]	1-hour 8-hour	45.8 13.1	1,471 590	1,517 603	10,000 2,500

NOTES

1. POPCO project, and ExxonMobil project's specific contribution concentrations are from the 1987 APCD ATC No. 5651 for the ExxonMobil SYU project, *Air Quality Impact Analysis*, *Table 6-20*.

2. CO impacts are adjusted upward from those presented in SEIR for the hourly CO emission increase to 6.34 lb/hr from the hourly rate assessed in the project SEIR of 0.97 lb/hr that occurred through implementation of Rule 342 controls and PTO 9215.

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7.0 CAP Consistency, Offset Requirements, and ERCs

7.1. General

Santa Barbara County has been classified as non attainment for the state eight-hour ozone standard as well as the state 24-hour and annual PM_{10} ambient air quality standards. The County is either in attainment of or unclassified with respect to all other state ambient air quality standards.

Santa Barbara County's air quality has historically violated federal ozone standards. Since 1999, however, local air quality data show that every monitoring location in the County complied with the federal one-hour ambient air quality standard for ozone. The Santa Barbara County Air Pollution Control District adopted the 2001 Clean Air Plan (2001 CAP) that demonstrated attainment of the federal one-hour ozone standard and continued maintenance of that standard through 2015. Consequently, on August 8, 2003, the United States Environmental Protection Agency (USEPA) designated Santa Barbara County as an attainment area for the federal one-hour ozone standard.

On June 15, 2004, USEPA replaced the federal one-hour ozone standard with an eight-hour ozone standard. This eight-hour ozone standard, originally promulgated by USEPA on July 18, 1997, was set at 0.08 parts per million measured over eight hours and is more protective of public health and more stringent than the federal one-hour standard. In March 2008, USEPA lowered that standard to 0.075 parts per million. While USEPA has yet to formally designate Santa Barbara County with respect to the 0.075 parts per million standard, the state has recommended to USEPA that Santa Barbara County be designated as attainment.

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 or maintenance of federal and state ambient air quality standards. Under APCD regulations, any modifications at the source that result in an emissions increase of any nonattainment pollutant exceeding 25 lbs./day must apply BACT (NAR). Additional increases will trigger offsets at the source or elsewhere so that there is a net air quality benefit for Santa Barbara County. These offset threshold levels are 55 lbs/day for all non-attainment pollutants except PM_{10} for which the level is 80 lbs/day. These thresholds apply to net emissions increases since November 15, 1990 as defined in District Rule 801. The Exxon – SYU Project has already exceeded the offset thresholds.

7.2. Clean Air Plan

On August 16, 2007, the APCD Board adopted the 2007 Clean Air Plan to chart a course of action that provided for ongoing maintenance of the federal eight-hour ozone standard through the year 2014 as well as the expeditious attainment of the state one-hour ozone standard. These plans were developed for Santa Barbara County as required by both the 1998 California Clean Air Act and the 1990 Federal Clean Air Act Amendments. Santa Barbara County has now attained the state one-hour ozone standard but does not attain the state eight-hour ozone standard.

In 2010 the APCD will update those provisions of the 2007 Clean Air Plan which demonstrate expeditious attainment of the state eight-hour ozone standard. No changes will be made to the

2007 Clean Air Plan sections which demonstrate continued maintenance of the federal eight-hour ozone standard.

7.3. Offset Requirements

7.3.1 NEI Offsets: Under APCD rules, POPCO is required to provide offsets for the project's operational net emission increase for NO_x, ROC, PM, PM_{10} and SO_2. In order to demonstrate a net air quality benefit, offsets have been adjusted to account for the distance between the project source and the offset source.

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 at the POPCO Gas Plant and the three OCS platforms. The specific offset requirements for the POPCO Gas Plant are detailed in Tables 7.1 for NO_x, Table 7.2 for ROC, Table 7.3 for SO_x and Table 7.4 for PM/PM_{10}.

7.4. Emission Reduction Credits

7.4.1 DOI # 0023/ERC Certificate No. 1006: On October 17, 2001 POPCO obtained ERC Certificate No. 1006 (DOI No. 0023) for emission reductions in NOx, ROC, CO, SOx, PM, and PM10 for planned removal of the utility boilers, Stretford Tailgas Cleanup Unit, and Boiler Fuel Gas System under the Synergy Project (ATC 10351 and ATC 10352). Part of these reductions would have been used to offset emission increases at Las Flores Canyon due to the Synergy Project. Since the Synergy Project was abandoned, the ERC created has been revoked.

7.4.2 DOI # 0034/ERC Certificate No. 114-1009: On October 13, 2004 POPCO obtained ERC Certificate No. 114-1009 (DOI No. 0034) for emission reductions in ROC for decreasing the minor leak detection threshold to 100 ppmv for 919 valves and 2,757 flange/connection components in hydrocarbon service at the POPCO and Las Flores Canyon facilities (ATC/PTO 11130 and ATC/PTO 11170). Part of these reductions were used to offset fugitive increases associated with the Heritage Gas Expansion Project.

Table 7.1 NOx Emission Offset Requirements

Oxides of Nitrogen (NOx) [1]

NEI EMISSIONS FROM PROJECT	Oxides of Nitrogen (NOx)	
	TPQ	TPY
POPCO Gas Plant [2]	0.15	0.64
Total NEI:	**0.15**	**0.64**

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor [3]	Offset Credit	
	TPQ	TPY		TPQ	TPY
1. ERC Certificate #0028 [4]	0.95	3.81	6	0.16	0.64
Total Offsets:	**0.95**	**3.81**		**0.16**	**0.64**

NOTES

1. NOx as NO_2
2. POPCO Gas Plant offset NEI liability based on ATC 9047 Mod -04, Table 5.8 (Facility NEI-90, Line 18b).
3. Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.
4. ERC Certificate #0028 is for ERCs generated due the shutdown of the Grefco Minerals diatomaceous earth processing plant in Lompoc. The face value of the certificate is 1.00 tpq NOx. The difference, 0.05 tpq NOx, is re-issued as a new certificate to POPCO.

Table 7.2 ROC Emission Offset Requirements

Reactive Organic Compunds (ROC)[1]

NEI EMISSIONS FROM PROJECT	Reactive Organic Compounds (ROC)	
	TPQ	TPY
POPCO Gas Plant [2]	0.96	3.85
De Minimis Transfer	0.0358	0.1432
Total NEI:	**1.00**	**3.99**

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor[3]	Offset Credit	
	TPQ	TPY		TPQ	TPY
1. ERC Certificate #0028 [4]	2.75	11.00	6	0.46	1.83
2. ERC Certificate #0026 [5]	0.76	3.02	1.5	0.50	2.01
3. ERC # 0079-0206 [6]	0.2780	1.1120	1.5	0.1853	0.7413
4. ERC # 0080-0307 [7]	0.3310	1.3240	1.5	0.2207	0.8827
5. ERC # 0081-0308 [8]	0.6570	2.6280	1.5	0.4380	1.7520
6. ERC # 0083-1103 [9]	0.6400	2.5600	6	0.1067	0.4267
Total Offsets:	**5.41**	**21.64**		**1.91**	**7.65**

NOTES

1. ROC as defined by APCD Rule 102.
2. POPCO Gas Plant offset NEI liability based on ATC 9047 Mod -04, Table 5.8 (Facility NEI-90, Line 18b).
3. Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.
4. ERC Certificate #0028 is for ERCs generated due the shutdown of the Grefco Minerals diatomaceous earth processing plant in Lompoc. The face value of the certificate is 2.75 tpq ROC and is used for this project in total.
5. ERC Certificate #0026 is for ERCs generated due the shutdown of the Santa Barbara Aerospace aircraft refurbishing facility in Santa Barbara. The face value of the certificate is 0.80 tpq ROC. The difference, 0.04 tpq ROC, is re-issued as a new certificate to POPCO.
6. Offset ratios set according to Table 4 of APCD Rule 802. Offset credit is determined by the ERC value by the offset ratio.
7. ERC Certificate #0079 is for ERCs generated due the shutdown of McGhan Medical Corporation's Carpinteria facility.
8. ERC Certificate #0080 is for ERCs generated due the shutdown of McGhan Medical Corporation's Goleta facility at 600 Pine Avenue.
9. ERC Certificate #0081 is for ERCs generated due the shutdown of BioEnterics Corporation facility at 1035 Cindy Lane in Carpinteria.
10. ERC Certificate #0083 is for ERCs generated due the shutdown of Grefco's Lompoc diatomaceous earth processing plant.

Table 7.3 SOx Emission Offset Requirements

Oxides of Sulfur (SOx) [1]

NEI EMISSIONS FROM PROJECT	Oxides of Sulfur	
	TPQ	TPY
POPCO Gas Plant [2]	3.24	12.92
Total NEI:	**3.24**	**12.92**

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor [3]	Offset Credit	
	TPQ	TPY		TPQ	TPY
1. ERC Certificate #0028 [4]	2.61	10.44	6	0.44	1.74
2. Reserved SOx ERCs [5]	3.35	13.41	1.2	2.79	11.18
Total Offsets:	**5.96**	**23.85**		**3.23**	**12.92**

NOTES

1. SOx as SO2

2. POPCO Gas Plant offset NEI liability based on ATC 9047 Mod -04, Table 5.8 (Facility NEI-90, Line 18b).

3. Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.

4. ERC Certificate #0028 is for ERCs generated due the shutdown of the Grefco Minerals diatomaceous earth processing plant in Lompoc. The face value of the certificate is 2.75 tpq SOx. The difference, 0.14 tpq SOx, is re-issued as a new certificate to POPCO.

5. Reserved ERCs are derived from PTO 5651 (1/27/99).

Table 7.4 PM Emission Offset Requirements

Particulate Matter (PM)/PM10 [1]

NEI EMISSIONS FROM PROJECT	Particulate Matter	
	TPQ	TPY
POPCO Gas Plant [2]	0.03	0.08
Total NEI:	**0.03**	**0.08**

EMISSION REDUCTION SOURCES (NEI)	Emission Reductions		Distance Factor [3]	Offset Credit	
	TPQ	TPY		TPQ	TPY
1. ERC Certificate #0028 [4]	0.13	0.50	6	0.02	0.08
Total Offsets:	**0.13**	**0.50**		**0.02**	**0.08**

NOTES

1. PM and PM10 as defined in APCD Rule 102. For this facility, PM and PM10 liabilities are equal.

2. POPCO Gas Plant offset NEI liability based on ATC 9047 Mod -04, Table 5.8 (Facility NEI-90, Line 18b).

3. Ratios set according to District Guidelines and based on source distance from the SYU project. The discounted offset values shown are the undiscounted offset values divided by the discount ratio.

4. ERC Certificate #0028 is for ERCs generated due the shutdown of the Grefco Minerals diatomaceous earth processing plant in Lompoc. The face value of the certificate is 0.125 tpq PM and 0.125 tpq of PM10 and is used for this project in total.

8.0 Lead Agency Permit Consistency

8.1. Prior Lead Agency Action

A Final Development Plan ("FDP") for the POPCO Gas Plant Expansion project was approved by the Santa Barbara County Planning Commission on November 4, 1994. The approved Plan contains a number of provisions that relate to the air quality aspects of the proposed project. The following is a summary of major conditions and their relationship to the APCD's evaluation and final decision on the project.

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

The issuance of ATC 9047 permit fulfills this requirement of the FDP.

FDP Condition E-3: Construction Plan: Prior to issuance of the land use permit, POPCO shall submit to the Planning and Development Department a plan, approved by the APCD, which includes measure to reduce NO_x , ROC, SO_x , and PM_{10} emissions produced during expansion construction activities.

The subject plan was jointly reviewed and approved by the APCD and Planning and Development.

FDP Condition E-4: Fugitive ROC Emissions.

This FDP condition required fugitive emissions related to new components to be fully offset if the new components generated more than 25 lb/day of ROC emissions. In addition, if the entire project's ROC net emission increases triggered emission offsets, those offsets were also to be secured to comply with this condition.

Because the proposed expansion actually decreased emissions from that of the existing facility's ROC emissions, none of the offset triggers specified in this condition were triggered.

FDP Condition E-5: Sulfur Recovery Unit Failure.

POPCO is required to install a system or operation procedure that mitigates to the extent feasible any predicted violation of the SO_2 ambient air quality standard which may occur during a SRU failure. POPCO has performed an AQIA to model the modified SRU unit failure. It has also proposed a SRU failure mitigation system that eliminates excess SRU acid gas venting to the flare (see discussion in the AQIA section of this permit). The installation and operations of this system are specified as a condition of this permit.

FDP Conditions E-7: *Facility Shall Emit No Detectable Odor*.

POPCO's agreement to continue to operate an odor monitoring station outside the POPCO facility but inside the ExxonMobil property, and expected operations of the POPCO facility in compliance with Rule 310 - Odorous Organic Sulfides should ensure that operations of the expanded facility comply with this condition of the FDP.

FDP Condition A-23: *Throughput Limitations.*

This permit has been issued with the maximum authorized offshore-to-onshore sour gas pipeline rate, POPCO plant sour gas input rate and characteristics, molten sulfur production limits, and maximum sales gas production rates consistent with the FDP.

8.2. Lead Agency Actions for PTO 8092

Pursuant CEQA Guidelines Section 15300.4 and Appendix A (*APCD List of Exempt Projects*) of the APCD's *Environmental Review Guidelines* document (10/95), the issuance of this Permit to Operate is exempt from CEQA.

9.0 Permit Conditions

This section lists the applicable permit conditions for the POPCO Gas Plant. Section 9 contains the permit's enforceable requirements.

Section 9.A lists the standard administrative conditions. Section 9.B lists 'generic' permit conditions, including emission standards, for all equipment in this permit. Section 9.C lists conditions affecting specific equipment. Section 9.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

A.1 **Condition Acceptance.** Acceptance of this operating permit by POPCO shall be considered as acceptance of all terms, conditions, and limits of this permit. [*Re: ATC 9047]*

A.2 **Grounds for Revocation.** Failure to abide by and faithfully comply with this permit or any Rule, Order, or Regulation may constitute grounds for revocation pursuant to California Health & Safety Code Section 42307 *et seq*. [*Re: ATC 9047]*

A.3 **Defense of Permit.** POPCO agrees, as a condition of the issuance and use of this permit, to defend at its sole expense any action brought against the APCD because of issuance of this permit. POPCO 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 POPCO of its obligation under this condition. The APCD shall bear its own expenses for its participation in the action. [*Re: ATC 9047]*

A.4 **Reimbursement of Costs**. All reasonable expenses, as defined in APCD Rule 210, incurred by the APCD, APCD contractors, and legal counsel for the activities listed below that follow the issuance of this permit, including but not limited to permit condition implementation, compliance verification and emergency response, directly and necessarily related to enforcement of the permit shall be reimbursed by POPCO as required by Rule 210. Reimbursable activities include work involving: Part 70 Federal Operating permit program, CEMS, modeling/AQIA, ambient air monitoring, DAS and data telemetry. Not withstanding the above, DAS system operation and maintenance shall be assessed fees based on a fee schedule consistent with Section 9.C of this permit. [*Re: ATC 9047, PTO 8092, PTO 9215, ATC 9693]*

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, POPCO shall make such records available or provide access to such facilities upon notice from the APCD. Access shall mean access consistent with California Health and Safety Code Section 41510 and Clean Air Act Section 114A. [*Re: ATC 9047]*

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: ATC 9047, PTO 8092, PTO 9215, ATC/PTO 9471, ATC 9471-1, ATC 9487, ATC 9675]*

A.7 **Consistency with Analysis.** Operation under this permit shall be conducted consistent with all data, specifications and assumptions included with the application and supplements thereof (as documented in the APCD's project file) and the APCD's analyses under which this permit is issued as documented in the Permit Analyses prepared for and issued with the permit. [*Re: ATC 9047, PTO 8092, ATC/PTO 9471, ATC 9471-1, ATC 9487, ATC 9675, ATC 9693]*

A.8 **Consistency with State and Local Permits.** Nothing in this permit shall relax any air pollution control requirement imposed on the project by the County of Santa Barbara in the POPCO Project Final Development Plan No. 93-FDP-015 and any subsequent modifications. [*Re: ATC 9047]*

A.9 **Equipment Maintenance.** All equipment permitted herein shall be properly maintained and kept in good working condition in accordance with the equipment manufacturer specifications at all times. [*Re: ATC 9047, PTO 9215, ATC 9693]*

A.10 **Conflict Between Permits.** The requirements or limits that are more protective of air quality shall apply if any conflict arises between the requirements and limits of this permit and any other permitting actions associated with the equipment permitted herein. [*Re: ATC 9047]*

A.11 **Complaint Response.** POPCO shall provide the APCD with the current name and position, address and 24-hour phone number of a contact person who shall be available to respond to complaints from the public concerning nuisance or odors. This contact person shall aid the APCD staff, as requested by the APCD, in the investigation of any complaints received, POPCO shall take corrective action, to correct the facility activity which is reasonably believed to have caused the complaint. [*Re: ATC 9047]*

A.12 **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: ATC 9047, 40 CFR Part 70.6.(a)(6), APCD Rule 1303.D.1]*

A.13 **Emergency Provisions.** The permittee shall comply with the requirements of the APCD, Rule 505 (Upset/Breakdown rule) and/or APCD Rule 1303.F, whichever is applicable to the emergency situation. In order to maintain an affirmative defense under Rule 1303.F, the permittee shall provide the APCD, in writing, a "notice of emergency" within two (2) working days of the emergency. The "notice of emergency" shall contain the information/documentation listed in Sections (1) through (5) of Rule 1303.F. [*Re: 40 CFR 70.6(g), APCD Rule 1303.F*]

A.14 **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.15 **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.16 **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, ATC 9047, PTO 8092, PTO 9215, ATC/PTO 9471, ATC 9471-1, ATC 9487, ATC 9675, ATC 9693*]

A.17 **Permit Life.** The Part 70 permit shall become invalid three years from the date of issuance unless a timely and complete renewal application is submitted to the APCD. Any operation of the source to which this Part 70 permit is issued beyond the expiration date of this Part 70 permit and without a valid Part 70 operating permit (or a complete Part 70 permit renewal application) shall be a violation of the CAAA, § 502(a) and 503(d) and of the APCD rules.

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

A.18 **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.19 **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 seven (7) days after discovery of the violation, but not later than six (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.20 **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, the monitoring methods used to determine compliance, whether the compliance was continuous or intermittent, and include detailed information on the occurrence and correction of any deviations from permit requirement. The reporting periods shall be each half of the calendar year, e.g., January through June for the first half of the year. These reports shall be submitted by September 1st and March 1st, 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.21 **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.22 **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.23 **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.

(d) 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.

(e) 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.24 **Credible Evidence.** Nothing in this permit shall alter or affect the ability of any person to establish compliance with, or a violation of, any applicable requirement through the use of credible evidence to the extent authorized by law. Nothing in this permit shall be construed to waive any defenses otherwise available to the permittee, including but not limited to, any challenge to the Credible Evidence Rule (see 62 Fed. Reg. 8314, Feb. 24, 1997), in the context of any future proceeding. [*Re: 40 CFR 52.12(c)*]

A.25 **Risk Management Plan – Section 112r.** POPCO shall comply with the requirements of 40 CFR 68 on chemical accident prevention provisions. The annual compliance certification must include a statement regarding compliance with this part, including the registration and submission of the risk management plan (RMP). [*Re: 40 CFR 68*]

9.B Generic Conditions

The generic conditions listed below apply to all emission units, regardless of their category or emission rates. These conditions are federally enforceable. These rules apply to the equipment and operations at the POPCO facility 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).** POPCO 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.
(c) POPCO shall determine compliance with the requirements of this Condition/Rule and Condition C.39, as specified below: [*Re: APCD Rule 302*]

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

B.4 **PM Concentration - South Zone (Rule 305).** POPCO 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).** POPCO shall not discharge into the atmosphere from any single source sulfur compounds, hydrogen sulfide, combustion contaminants and carbon monoxide in excess of the standards listed in Sections A, B and G of Rule 309. POPCO shall not discharge into the atmosphere from any fuel burning equipment unit, sulfur compounds, nitrogen oxides or combustion contaminants in excess of the standards listed in Section E and F of Rule 309. [*Re: APCD Rule 309*]

B.6 **Sulfur Content of Fuels (Rule 311).** POPCO shall not burn fuels with a sulfur content in excess of 0.5% (by weight) for liquid fuels and 239 ppmvd or 15 gr/100scf (calculated as H_2S) for gaseous fuels. Compliance with this condition shall be based on continuous monitoring of the fuel gas with H_2S analyzers, daily sorbent tube samples, quarterly total sulfur content measurements of the fuel gas using 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.7 **Organic Solvents (Rule 317).** POPCO shall comply with the emission standards listed in Section B of Rule 317. Compliance with this condition shall be based on POPCO's compliance with the *Solvent Usage* condition in this permit. [*Re: APCD Rule 317*]

B.8 **Solvent Cleaning Operations (Rule 321).** POPCO shall comply with the operating requirement, equipment requirements and emission control requirements for all solvent cleaners subject to this Rule. Compliance shall be based on APCD inspection of the existing cold solvent cleaner and a thorough ATC application review for future solvent cleaners (if any). [*Re: APCD Rule 321*]

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

B.10 **Architectural Coatings (Rule 323).** POPCO shall comply with the emission 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 the *Solvent Usage* condition in this permit and facility inspections. [*Re: APCD Rule 323*]

B.11 **Disposal and Evaporation of Solvents (Rule 324).** POPCO shall not dispose through atmospheric evaporation more than one and a half gallons of any photochemically reactive solvent per day. Compliance with this condition shall be based on the *Solvent Usage* condition in this permit and facility inspections. [*Re: APCD Rule 324*]

B.12 **Continuous Emissions Monitoring (Rule 328).** POPCO shall comply with the requirements of Section C, F, G, H and I of Rule 328. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit as well as on-site inspections. [*Re: APCD Rule 328*]

B.13 **Polyester Resin Operations (Rule 349).** POPCO shall comply with the requirements of Section D of Rule 352. Compliance shall be based on the monitoring requirements of Sections E and F and on-site inspections. [*Re: APCD Rule 349*]

B.14 **Natural Gas-Fired Fan Type Central Furnaces and Residential Water Heaters (Rule 352).** POPCO shall comply with the requirements of Section D and E of Rule 352. Compliance shall be based on the monitoring requirements of Section F and on-site inspections. [Re: *APCD Rule 352*].

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]

B.16 **Large Water Heaters and Small Boilers (Rule 360).** Any boiler, water heater, steam generator, or process heater rated greater than or equal to 75,000 Btu/hr and less than or equal to 2.000 MMBtu/hr and manufactured after October 17, 2003 shall be certified per the provisions of Rule 360. An ATC/PTO permit shall be obtained prior to installation of any grouping of boilers, water heaters, steam generators, or process heaters subject to Rule 360 whose combined system design heat input rating exceeds 2.000 MMBtu/hr.

B.17 **CARB Registered Portable Equipment.** State registered portable equipment shall comply with State registration requirements. A copy of the State registration shall be readily available whenever the equipment is at the facility. [*Re: APCD Rule 202*]

B.18 **Oil and Natural Gas Production MACT.** POPCO shall comply with the following MACT requirements: [*Re:* 40 CFR 63, Subpart HH]

(a) <u>NGL Storage Vessels:</u>

(i) *Operational Limits (40 CFR 63.766(b)(2)):*

(1) POPCO shall operate the storage vessels with no detectable emissions at all times that material is in the storage vessel. No detectable emissions is defined as emissions less than 500 ppmv (40 CFR 63.772(c)(8)).

(2) One or more safety devices that vent directly to the atmosphere may be used on the storage vessels.

(ii) *Inspection and Monitoring Requirements:*

(1) POPCO shall perform inspection and monitoring per APCD Rule 331 to ensure fugitive emission components on the storage vessels operate at no detectable emissions. Inspection results shall be submitted with the Notification of Compliance Status Report.

(iii) *Recordkeeping requirements (40 CFR 63.774(b)):*

(1) POPCO shall retain at least five (5) years of information as required in this section. The most recent twelve (12) months of records shall be kept in a readily accessible location; the previous four (4) years may be retained offsite. Records may be maintained in hard copy or computer-readable form (40 CFR 63.774(b)(1)).

(2) POPCO shall maintain records indentifying ancillary equipment and compressors controlled under 40 CFR Part 60, subpart KKK (40 CFR 63.774(b)(9)).

(iv) *Reporting Requirements (40 CFR 63.775):*

(1) POPCO shall submit the Periodic Report semiannually beginning August 17, 2003.

(2) POPCO shall submit a report within one hundred eighty (180) days of a change to the process or information submitted in the Notification of Compliance Status Report per 40 CFR 63.775(f).

(b) <u>Sulfinol Glycol Regeneration System Connected to the Sulfinol Reboiler Heater</u>

(i) *Inspection and Monitoring Requirements (40 CFR 63.773(c)):*

(1) POPCO shall conduct annual inspections of the storage vessels according to Method 21 to demonstrate that the components or connections operate with no detectable emissions. No detectable emissions is defined as emissions less than 500 ppmv (40 CFR 63.772(c)(8)).Inspection results shall be submitted in the Periodic Report.

(2) POPCO shall conduct annual visual inspections for defects that could result in air emissions per APCD Rule 331.

(ii) *Reporting Requirements (40 CFR 63.775):*

(1) POPCO shall submit the Periodic Report semiannually beginning August 17, 2003.

(2) POPCO shall submit a report within one hundred eighty (180) days of a change to the process or information submitted in the Notification of Compliance Status Report per 40 CFR 63.775(f).

(c) <u>General Recordkeeping</u>

(i) *POPCO shall maintain records of (40 CFR 63.10(b)(2)):*

(1) The occurrence and duration of each startup, shutdown, or malfunction of operation;

(2) The occurrence and duration of each malfunction of the air pollution control equipment;

(3) Actions taken during periods of startup, shutdown, and malfunction when different from the procedures specified in POPCO's startup, shutdown, and malfunction plan (SSMP);

(4) All information necessary to demonstrate conformance with POPCO's SSMP when all actions taken during periods of startup, shutdown, and malfunction are consistent with the procedures specified in such plan;

(5) All required measurements needed to demonstrate compliance with a relevant standard;

(6) Any information demonstrating whether a source is meeting the requirements for a waiver of record-keeping or reporting requirements under this condition.

(ii) POPCO shall maintain records of SSM events indicating whether or not the SSMP was followed;

(iii) POPCO shall submit a semi-annual startup, shutdown, and malfunction report as specified in 40 CFR 63.10(d)(5). This report is only required if a startup, shutdown, or malfunction occurred during the six (6) month reporting period. The report shall be due by July 30th and January 30th.

B.19 **Emergency Episode Plan.** During emergency episodes, POPCO shall implement the APCD approved Emergency Episode Plan for the POPCO Gas Plant. The content of the plan shall be in accordance with the provisions of Rule 603. [Re: *APCD Rule 1303, 40 CFR 70.6*]

9.C Requirements and Equipment Specific Conditions

C.1 **External Combustion.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
External Combustion Equipment		
Utility Boiler B-801 A	B-801 A	2350
Utility Boiler B-801 B	B-801 B	2351
Sulfinol TEG Reboiler	E-251	2352
TEG Regenerator Boiler	E-121	2353
Forced Air Furnace	F-A412	8792

(a) Emission Limits: The mass emissions from the Utility Boilers shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance shall be based on the monitoring, recordkeeping and reporting conditions of this permit. In addition to the monitoring, recordkeeping, and reporting conditions of this permit, compliance with the NO_x mass emission limits for the Utility Boilers shall be based on CEMS and annual source testing. In addition, the following specific emission limits apply:

(i) *NO_x and CO Limits* – Except during periods of startup (defined as the time period within 2 hours after a continuous period in which fuel flow to unit is shut off for 30 minutes or longer), the emissions from the Utility Boilers shall not exceed the limits listed below. Compliance shall be based on semi-annual source testing for all pollutants.

Operating Mode	NOx (as NO_2)	CO
Utility Boiler B-801A	30 ppmvd at 3% O2 or 0.036 lb/MMBtu	100 ppmvd at 3% O2 or 0.073 lb/MMBtu
Utility Boiler B-801B	30 ppmvd at 3% O2 or 0.036 lb/MMBtu	100 ppmvd at 3% O2 or 0.073 lb/MMBtu

(ii) Compliance with the NO_X and CO concentration limits shall take into account dilution of the boiler stack gases with TGU off gas according to the following formulae:

(1) Adjusted Stack ppmv = Raw Stack ppmv * Stack Flow/(Stack Flow - Off gas Flow)

(2) Adjusted Stack % O_2 = Raw Stack %O_2 * Stack Flow/(Stack Flow - Off gas Flow)

(3) ppmv (@3% O_2) = Adjusted Stack ppmv * (20.95-3.0)/(20.95- Adjusted Stack %O_2)

(iii) All heat content data shall be higher heating value (HHV) based. Stack flows and off-gas flows shall be determined on a wet basis.

(iv) If no off-gas is present in either Boiler A or Boiler B, then emissions for the boiler without off gas shall not exceed the following limits:

(1) Emissions of NO_x shall not exceed 1.48 lb/hr.
(2) Emissions of SOx shall not exceed 0.11 lb/hr

(v) If tailgas is present in either Boiler A or Boiler B, then emissions for the boiler with off gas shall not exceed the following limits:

(1) Emissions of NO_x shall not exceed 1.68 lb/hr.
(2) Emissions of SO_x shall not exceed 5.44 lb/hr

(vi) If off gas is present in both Boiler A and Boiler B, then the combined emissions for both boilers with off gas shall not exceed the following limits:

(1) Emissions of NO_x shall not exceed 3.15 lb/hr.
(2) Emissions of SO_x shall not exceed 5.67 lb/hr

(b) Operational Limits: The following operational limits apply to the external combustion equipment as specified:

(i) *Utility Boiler Fuel Gas Sulfur Limit* - POPCO shall use plant fuel gas at all times for the Utility Boilers. The plant fuel gas shall not contain total sulfur compounds in concentrations exceeding 24 ppmvd (calculated as H_2S at standard conditions). Compliance with this condition shall be based on monitoring, recordkeeping and reporting requirements of this permit.

(ii) *TEG Reboiler/Air Furnace Fuel Gas Sulfur Limit* - POPCO shall use PUC quality natural gas at all times for the TEG Reboilers and the Air Furnace. The concentration of:

(1) Hydrogen sulfide in the gas shall not exceed 0.25 grains per hundred standard cubic feet (4 ppmvd as H_2S);
(2) Total sulfur in the gas shall not exceed 5 grains per hundred standard cubic feet (80 ppmvd calculated as H_2S).
(3) Compliance with this condition shall be based on monitoring, recordkeeping and reporting requirements of this permit.

(iii) *Utility Boiler - Fuel Gas Usage Limits* - POPCO shall comply with the following usage limits (HHV based):

(1) Utility Boiler B-801A: 41.000 MMBtu/hr; 984 MMBtu/day; 89,790 MMBtu/quarter; 359,160 MMBtu/year

(2) Utility Boiler B-801B: 41.000 MMBtu/hr; 984 MMBtu/day; 89,790 MMBtu/quarter; 359,160 MMBtu/year

(a) Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit. POPCO shall use the most recent heating value analysis in conjunction with the fuel gas meter reading to calculate the heat input to each boiler.

(iv) *Utility Boiler –TGU Off Gas Input Limits* - POPCO shall comply with the following usage limits (HHV based):

(1) TGU Off Gas to Boilers B-801A/B: 5.620 MMBtu/hr; 135 MMBtu/day; 12,308 MMBtu/quarter; 49,231 MMBtu/year Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit. POPCO shall use the most recent heating value analysis in conjunction with the TGU off gas meter readings to calculate the heat input to the boilers.

(v) *Steam Injection Operating Limits* –The following conditions describing steam injection into Utility Boilers B-801A and B-801B shall apply to comply with the emission limits of this permit:

(1) Injection of 50 psig steam shall be limited to no more than 650 lb/hr, as verified by an equivalent steam delivery pressure to the Utility Boiler burner steam injection wand of no more than 10 psig;

(c) Monitoring: The Utility Boilers in this section are subject to all the monitoring requirements listed in Table 4.10 and APCD Rule 342.E, G and I. The source test methods In Rule 342.H shall be used. In addition, POPCO shall:

(i) *Utility Boiler Fuel Meters* – The amount of fuel gas combusted in each Utility Boiler shall be measured using a permanently installed APCD-approved in-line fuel meter. POPCO shall obtain written APCD approval prior to implementing any changes to the meter configuration.

(ii) *TGU Off Gas Meters* – The volume of TGU off gas directed to each Utility Boiler shall be metered using APCD-approved meters.

(iii) *Source* Testing – POPCO shall source test the Utility Boilers according to the *Source Testing* condition in this permit. More frequent testing may be required, as determined by the APCD, if full operating loads have not been achieved.

(iv) *CEMS* – POPCO shall monitor the emission and process parameters listed in Table 4.10 for the life of the project POPCO and shall maintain and operate continuous in stack monitoring equipment for the Utility Boilers for emissions of nitrogen oxides (as NO_2) and sulfur oxides (as SO_2) consistent with APCD Rule 328, the APCD-approved CEMS Plan for the POPCO facility and Table 4.10.

(v) *Boiler Fuel Gas Data* – POPCO shall monitor the total sulfur content of the plant fuel gas used in the Utility Boilers by (a) weekly sorbent tube (or equivalent APCD-approved) readings of hydrogen sulfide, and (b) quarterly gas samples for third party lab analyses for hydrogen sulfide, total reduced sulfur compounds and higher heating value (HHV). The readings from the weekly sorbent tubes shall be adjusted upward to take into account the non-hydrogen sulfide reduced sulfur compounds in the fuel gas from the last analysis. The APCD may require more frequent lab analyses upon request. POPCO shall utilize the APCD-approved *Fuel Gas Sulfur and HHV Reporting Plan.*

(vi) *Sales (PUC Quality) Fuel Gas Data* – POPCO shall continuously monitor the hydrogen sulfide content (as H_2S) of the sales (PUC Quality) fuel gas used in the TEG Reboilers and Forced Air Furnace using one APCD-approved monitor. This monitor shall adhere to the APCD's CEMS Protocol document and APCD Rule 328 requirements regarding CEMS. On a quarterly basis, POPCO shall take gas samples for third party lab analyses for: hydrogen sulfide content, total reduced sulfur compounds and the higher heating value (HHV). The APCD may require more frequent lab analyses upon request. POPCO shall utilize the APCD-approved *Fuel Gas Sulfur and HHV Reporting Plan*.

(vii) *TGU Off Gas Data* – POPCO shall monitor the higher heating value of the TGU off gas combusted in the Utility Boilers by taking quarterly gas samples for third party lab analyses for the higher heating value (HHV). The APCD may require more frequent lab analyses upon request. POPCO shall utilize the APCD-approved *Fuel Gas Sulfur and HHV Reporting Plan*.

(viii) *Steam Injection* – POPCO shall monitor the steam delivery pressure to Utility Boilers B-801A and B-801B burner steam injection wand using a dedicated pressure gage.

(d) <u>Recordkeeping</u>: The Utility Boilers listed in this section are subject to the recordkeeping requirements listed in Table 4.10 and Rule 342.I. POPCO shall record the emission and process parameters listed in Table 4.10. In addition, POPCO shall:

(i) *Utility Boiler Fuel Gas Use* - The total amount of boiler fuel gas combusted in each Utility Boiler shall be recorded on a daily, quarterly and annual basis in units of standard cubic feet. Heat input to each boiler from plant fuel gas on a daily, quarterly, and annual basis shall be calculated after each gas HHV analysis in a million BTUs (x.xxx) format.

(ii) *TGU Off Gas Input* **-** The total amount of TGU off gas combusted in each Utility Boiler shall be recorded on a daily, quarterly and annual basis in units of standard cubic feet. The heat input to each boiler from TGU off gas on a daily, quarterly, and annual basis shall be calculated after each gas HHV analysis in a million BTUs (x.xxx) format.

(iii) *Boiler Fuel Gas Data* **-** A logbook or electronic file shall be maintained that records the weekly sorbent tube readings and the quarterly lab analysis results. The logbook or electronic file shall also store as backup documentation, a photocopy picture of each sorbent tube and the laboratory reports, including chain of custody forms.

(iv) *Sales (PUC Quality) Fuel Gas Data* **-** A logbook or electronic file shall be maintained that records the highest weekly H_2S analyzer readings and the quarterly lab analysis results. The logbook shall also store as backup documentation, a copy of the analyzer data and the laboratory reports, including chain of custody forms.

(v) *TGU Off Gas Data* – A logbook or electronic file shall be maintained that records the quarterly lab analysis results. The logbook shall also store as backup documentation, a copy of the laboratory reports, including chain of custody forms.

(vi) *Steam Injection* - A logbook or electronic file shall be maintained that records all instances of steam gas pressure exceeding 10 psig.

(vii) *Maintenance and Calibration Logs* – A logbook or electronic file shall be kept that documents all maintenance and calibration performed for the boilers, emission control systems, fuel flow meters and other associated monitoring equipment.

(viii) *H_2S Monitors* – POPCO shall maintain records as required by APCD Rule 328 for the sales gas CEMS analyzer according to the APCD-approved CEMS Plan for the POPCO facility and Table 4.12.

(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: ATC 9047, PTO 8092, PTO 9215, ATC 9693, ATC/PTO 10932]*

C.2 **Thermal Oxidizer.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
Thermal Oxidizer	*A-803*	*7065*
Planned Purge/Pilot Gas		102614
Planned Compressor Seal Leakage		102615
Planned Baseline System		107202
Planned Startups/Maintenance		102616
Unplanned Other - Miscellaneous		108095
Unplanned Other - SRU Failure		102617

(a) Emission Limits: Mass emissions from the flare relief system listed above shall not exceed the limits listed in Tables 5.3 and 5.4. 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 5.3 shall not be considered enforceable limits. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit.

Continuous planned flaring emissions are permitted for the hydrocarbon flare header at levels above the minimum detection limit of the hydrocarbon flare meter due to baseline system leakage. Continuous planned flaring is permitted for the Acid Gas flare header at levels greater than one-half the minimum detection limit for the acid gas flare header, but less than the detection limit of that meter, due to compressor seal leakage and baseline system leakage. 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, pilot, 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	0.200	4.800	0.438	1.752
Pilot	2.000	48.000	4.380	17.520
Continuous – HC/AG Header, Baseline System Leakage [f]	0.600	14.400	1.314	5.256
Continuous – AG Header Compressor Seal Leakage [g]	0.311	7.464	0.681	2.724
Planned Other [h]			32.680	130.720
Unplanned Other - Miscellaneous			0.75	1.50
Unplanned Other - SRU Failure [i]			0.00148	0.00148

(ii) The hourly limits shall be enforced on an hourly basis and the daily limits shall be enforced on a daily basis.

(iii) *Flare Purge/Pilot Fuel Gas Sulfur Limits* - The pilot fuel gas combusted in the thermal oxidizer shall not exceed a total sulfur content of 24 ppmv. The purge fuel gas combusted in the thermal oxidizer shall meet the following:

(1) Hydrogen sulfide in the fuel gas shall not exceed 0.25 grains per hundred standard cubic feet (4 ppmvd as H_2S);
(2) Total sulfur in the fuel gas shall not exceed 5 grains per hundred standard cubic feet (80 ppmvd calculated as H_2S).
(3) Compliance with this condition shall be based on monitoring, recordkeeping and reporting requirements of this permit.

(iv) *Planned Continuous Flaring Sulfur Limits* - The sulfur content of all gas burned as continuous flaring in the hydrocarbon flare header (i.e., baseline system leakage) shall not exceed 239 ppmv total sulfur. The sulfur content of all gas burned as continuous flaring in the acid gas flare header (i.e., compressor seal leakage and baseline system leakage) shall not exceed 239 ppmv total sulfur. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(v) *Rule 359 Technology Based Standards* - POPCO 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.

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[f] *Baseline System Leakage* shall be measured and calculated for each flare header using APCD-approved methods using the following calculations: (i) HC Flare Header: BSL_{HC} = (total aggregate HC flare flow) – (HC header purge flow) – (HC flare event flow); (ii) AG Flare Header: BSL_{AG} = (total aggregate AG flare flow) – (AG header purge flow) – (compressor seal leakage flow) - (AG flare event flow).
[g] *Compressor Seal Leakage* shall be measured and calculated using APCD-approved methods.
[h] *Planned Other* flaring only includes startup and maintenance events. This category does not include maintenance activities (and associated startups) due to equipment failure, breakdown or other non-planned event or activity.
[i] *Unplanned Other* - SRU Failures is limited to 1480 scf/event, with an event limited to 28 seconds

(vi) *Flaring Modes* - POPCO shall operate the thermal oxidizer consistent with APCD P&P 6100.004 (*Planned and Unplanned Flaring Events*). Section 4.5.2 of this permit defines each of the modes and flare categories and is specific to this facility. If POPCO is unable to comply with the infrequent planned 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 5.3.

(vii) *Rule 359 Planned Flaring Target Volume Limit* - Pursuant to Rule 359, POPCO shall not flare more than 18.20 million standard cubic feet per month during planned flaring events.

(viii) *Rule 359 Flare Minimization Plan* - POPCO shall implement the requirements of the APCD-approved Rule 359 Flare Minimization Plan.

(ix) *BACT* – For increases in Planned Flaring due to baseline system leakage, compressor seal leakage and purge gas, POPCO shall: (1) use purge gas that meets sales gas quality; (2) properly maintain the thermal oxidizer combustors; (3) use sales gas quality gas in the compressors; and, (4) limit the sulfur content of the purge gas to 80 ppmv (as H_2S) and the hydrogen sulfide content to 4 ppmv. POPCO shall implement the APCD-approved *Thermal Oxidizer Combustor Maintenance Plan* documenting the maintenance procedures and schedules used comply with item (2) above, for the life of the POPCO facility. The APCD-approved Plan is an enforceable part of this permit.

(x) *Planned Flaring Hourly Limit* – No planned flaring activity in any one-hour shall exceed a rate of 0.76 MMSCF, or generate the equivalent of 900 MMBtu of gross heat release in the flare. The 0.76 MMSCF volume limit may only be exceeded in any hour if the 900 MMBtu gross heat release limit is not also exceeded. The flared gas heating value for each hour of planned flaring shall be obtained by POPCO, using an APCD-approved analytic technique, to utilize the 900 MMBtu limitation. Further, planned flaring activities for startups and shut downs shall not exceed a continuous uninterrupted duration of 24 hours.

(xi) *Unplanned Flaring Requirements* – The sulfur content of all gas burned during *Unplanned Other - Miscellaneous* flaring events shall not exceed 239 ppmv total sulfur. The above requirement shall not apply to SRU –Failures that meet the *Unplanned Other- SRU Failure* volume limits in 9.C.2(b)(i) above. Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit.

(1) POPCO shall obtain breakdown and/or variance relief pursuant to APCD Regulation V for all unplanned flaring events outside of the allowances for *Unplanned Other - Miscellaneous* and *SRU Failure* categories. (N<u>ote: the requirements of Regulation V must be fully satisfied to obtain this relief</u>). In no case shall such unplanned flaring outside these two permitted categories (Item #166, A-803 and Exhibit C-2 to POPCO's PTO application dated October, 1983) occur for more than one continuous hour nor more than a total of two hours in

any 24-hour period and the worst case emergency flare event shall not exceed 2.49 MMSCF/hr.

(xii) The flare and all associated relief systems shall be properly operated and maintained to minimize emissions to the maximum extent feasible. Flaring operations due in whole or in part to the lack of equipment repair or maintenance are prohibited. Except as expressly provided above, the operation of the flare shall comply with the Flaring Analysis of October 1983.In addition, flare operations shall comply with all applicable District Rules and Regulations.

(xiii) *Tailgas Incineration at ZTOF* – POPCO may incinerate no more than 5.62 MMBtu/hr of treated tail gas in the thermal oxidizer. Treated tail gas may be incinerated in the thermal oxidizer for no more than 8 hours/day, 16 hours/quarter, and 64 hours/year.

(c) Monitoring: The equipment in this section is subject to all the monitoring requirements listed in Table 4.11 and APCD Rule 359.G. The test methods In Rule 359.E. shall be used. POPCO shall monitor the emission and process parameters listed in Table 4.11 for the life of the project. In addition, the following monitoring requirements apply to the flare relief system:

(i) *Flare Event 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 POPCO's *Process Monitor Calibration and Maintenance Plan*. An event is defined as an hourly average flow rate in excess of the event threshold listed below. An event is determined on a clock-hour basis. During a flaring episode, 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 Threshold (scfh)**	**Meter Minimum Detection Level (scfh)**
Hydrocarbon	500	45
Acid Gas	500	490

(1) All flaring not classified as an event pursuant to the above definition shall be aggregated as a single hourly, daily, quarterly and annual volume and recorded in the *Continuous – HC/AG Header, Baseline System Leakage* flaring category. Continuous flaring greater than the event thresholds listed above is prohibited for any flaring category

(ii) *Purge/Pilot Gas* - POPCO shall monitor the total sulfur and hydrogen sulfide content of the sales gas used in the thermal oxidizer as purge and pilot gas by (a) on a in-line continuous hydrogen sulfide analyzer for the POPCO sales, and (b) quarterly gas samples for third party lab analyses for hydrogen sulfide, total reduced sulfur compounds and higher heating value (HHV). The readings from the analyzer shall be adjusted upward to take into account the average non-hydrogen sulfide reduced sulfur compounds in the fuel gas from the last analysis. The APCD may require more frequent lab analyses upon request. POPCO shall utilize the APCD-approved *Fuel Gas Sulfur and HHV Reporting Plan*. (conditionally approved 10/29/98).

(iii) *Pilot Gas Flow Meter* - POPCO shall continuously monitor the combined pilot gas flow to the thermal oxidizer using an APCD-approved meter.

(iv) *Hydrocarbon and Acid Gas Meters* – POPCO shall continuously monitor the flare gas volumes in the hydrocarbon and acid gas flare headers using the APCD-approved *Flare Volume Metering System* meters (Re: ATC 9487). The Thermal Oxidizer Pilot Fuel Gas metering system output and all the Hydrocarbon and Acid Gas flow metering system outputs will be tied into the facility's Distributed Control System ("DCS") control/monitoring system. The DCS will be capable of tracking instantaneous flows, as well as recording cumulative flows measured by the above-specified meters. Six-minute average instantaneous flow rates (in units of scfh) and one-hour average flow rates shall be telemetered to the APCD's DAS.

(v) *Meter Calibrations* – The four (4) Flare Volume Meters and the Thermal Oxidizer Pilot Fuel Gas Meter shall be calibrated and maintained in accordance with the meter manufacturer's procedures and frequency. All meters shall be calibrated at least once every six-calendar months, not to exceed seven calendar months between calibrations.

(vi) *Compressor Seal Meters* – POPCO shall operate the APCD-approved gas flow meters for measuring compressor seal leakage flow rates.

(vii) *Purge Gas Flow Meters* – POPCO shall operate the APCD-approved flow indicator meters for measuring all purge gas flow to the hydrocarbon and acid gas flare headers.

(viii) *Data for Acid Gas Header Flaring Events* – During any flare event in the Acid Gas flare header system, measurement of the hydrogen sulfide content of the flared acid gas shall be measured by sorbent tube (or other APCD-approved method) within one hour of flare event initiation, and hourly thereafter for extended flaring events. For each flare event, a record of the date, start time, duration, hydrogen sulfide content(s), assumed flared gas high heating value in Btu/scf and the reason for the Acid Gas flaring event shall be kept.

(ix) *Data for Hydrocarbon Header Flaring Events* – During any flare event in the Hydrocarbon flare header system measurement of the hydrogen sulfide content of the flared hydrocarbon gas shall be measured by sorbent tube (or other APCD-approved method) within one hour of flare event initiation, and hourly thereafter for extended flaring events. For each flare event, a record of the date, start time, duration, hydrogen sulfide content(s), assumed flared gas high heating value in Btu/scf and the reason for the hydrocarbon-flaring event shall be kept.

(x) *Flaring Sulfur Content Correction* – During non-flaring events, POPCO shall sample, on a weekly basis, the hydrocarbon and acid gas flare headers to determine the hydrogen sulfide content using sorbent tubes. On an annual basis, gas samples shall be obtained from each flare header for third party lab analyses of hydrogen sulfide and total reduced sulfur compounds. To correct for the total sulfur content, POPCO shall add the prior year's non-hydrogen sulfide reduced sulfur compounds analysis result to the sorbent tube readings. This data shall be used to determine SO_x emissions associated with non-event flaring. POPCO shall perform additional testing of the sulfur content and hydrogen sulfide content, using approved test methods, as requested by the APCD.

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in Table 4.11 and Rule 359.H. POPCO shall record the emission and process parameters listed in Table 4.11. In addition, the following recordkeeping conditions apply to the thermal oxidizer:

(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; the type of event as defined by APCD P&P 6100.004 (e.g., Planned - Continuous, –Planned – Frequent, Planned – Infrequent, etc.); and, the APCD Breakdown and/or Variance number for each Unplanned Flaring event. The volumes of gas combusted and resulting mass emissions of all criteria pollutants for each type of event shall also be summarized for a cumulative summary for each day, quarter and year.

(ii) *Pilot Gas Volumes/Mass Emissions* - The total volume of pilot fuel gas and resulting mass emissions of all criteria pollutants combusted in the thermal oxidizer shall be recorded on a daily, weekly, quarterly and annual basis. POPCO may petition the APCD to eliminate the requirement for daily recordkeeping. The petition shall include all daily records from the prior year and POPCO's analyses showing that weekly records provide an equivalent method of determining compliance with the daily volume limits. Upon approval of the petition by the APCD, the weekly data shall be used be used to record and report daily gas volumes and emissions.

(iii) *Purge Gas Volumes/Mass Emissions* - The volume of purge fuel gas and resulting mass emissions of all criteria pollutants combusted in the thermal oxidizer shall be recorded on a weekly, quarterly and annual basis. POPCO may petition the APCD to revise the recordkeeping frequency. The petition shall include all weekly records from the prior year and POPCO's analyses showing that monthly records provide an equivalent method of determining compliance with the daily volume limits. Upon approval of the petition by the APCD, the monthly data shall be used to record and report daily gas volumes and emissions.

(iv) *Compressor Seal Leakage Gas Volumes/Mass Emissions* - The volume of compressor seal leakage and resulting mass emissions of all criteria pollutants combusted in the thermal oxidizer shall be recorded on a weekly, quarterly and annual basis. POPCO may petition the APCD to eliminate the requirement for weekly recordkeeping. The petition shall include all weekly records from the prior year and POPCO's analyses showing that monthly records provide an equivalent method of determining compliance with the daily volume limits. Upon approval of the petition by the APCD, the monthly data shall be used to record and report daily gas volumes and emissions.

(v) *Baseline System Leakage Gas Volumes/Mass Emissions* - The volume of baseline system leakage [j] gas in both the hydrocarbon and acid gas headers and resulting mass emissions of all criteria pollutants combusted in the thermal oxidizer shall be recorded on a daily, quarterly and annual basis. POPCO shall use APCD-approved methods to measure and calculate the baseline system leakage in each flare header. The basis for each baseline system leakage volume calculation shall be clearly documented.

(vi) *Hydrocarbon and Acid Gas Meters (Telemetered Data)* – POPCO shall telemeter both 6-minute average instantaneous and clock-hour average instantaneous flow rates (in units of scfh) to the APCD's DAS.

(vii) *Maintenance and Calibration Logs* – Maintenance and calibration logs of all the Flare Volume Metering system meters and Thermal Oxidizer Pilot Fuel Gas Metering system meters shall be kept on site by the permittee and made available for APCD inspection upon request.

(viii) *Rule 359 Planned Monthly Volumes* – POPCO shall record in a log the total planned flaring volumes for each month.

(e) <u>Reporting</u>: 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 8092, ATC 9047, ATC 9487, ATC 9047-4, 40 CFR 70.6*)

[j] As defined in §9.C.2.(b)(i)

C.3 **Fugitive Hydrocarbon Emissions Components.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
Fugitive Components - Gas/Light Liquid		
Valves - Unsafe		7070
Valves - Bellows / Background ppmv		7066
Valves - Category B		7068
Valves - Category C		106397
Valves - Category F		9712
Valves - Category J		7067
Flanges/Connections - Accessible/Inaccessible		7071
Flanges/Connections - Unsafe		7074
Flanges/Connections - Category B		7072
Flanges/Connections - Category C		7073
Compressor Seals - To VRS		7079
PSV - To Atm/Flare		7075
Pump Seals - Single		7081
Pump Seals - Dual/Tandem		7080

(a) Emission Limits: Mass emissions from the gas/condensate service (sub-total) components listed above shall not exceed the limits listed in Tables 5.3 and 5.4. 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 POPCO shall meet the following requirements:

(i) *VRS Use* - The vapor recovery and gas collection (VR & GC) systems at the POPCO Gas Plant 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 for POPCO {*POPCO I&M Manual for Control of Reactive Organic Compound Emissions* shall be implemented for the life of the project. The *I&M Plan* shall be consistent with the provisions of Tables 4.1 of this permit, and 4.2 through 4.4 of this permit, APCD Rule 331, BACT requirements and NSPS Subpart KKK (*Standards of Performance for Equipment Leaks of VOC from Onshore Natural Gas Processing Plants*). Furthermore, POPCO shall implement a BACT component identification system, including the use of component tagging, recordkeeping and reporting. The *I&M Plan*, and any subsequent APCD approved revision, is incorporated by reference as an enforceable part of this permit.

(iii) *Leakpath Count* - The total component-leakpath count listed in POPCO's most recent I&M component-leakpath inventory shall not exceed the total component-leakpath count listed in Table 5.1 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 a compressor, vapor recovery, flare header or other APCD-approved control device.

(v) *BACT* - POPCO shall apply BACT, as defined in Tables 4.1 and 4.2 through 4.4, to those component-leakpaths in hydrocarbon service installed pursuant to ATC 9047, ATC 9675, ATC 9047-2, ATC 9047-4, and ATC/PTO 11130 for the life of the project. This requirement applies to components subject to the *de minimis* exemption of Rule 202 as well as projects that do not trigger the BACT threshold of Rule 802 and equivalent routine replacements.

(vi) *NSPS KKK* - For all permitted and future component-leakpaths in hydrocarbon service, POPCO shall comply with the emission standard requirements of 40 CFR 60.632, as applicable.

(vii) **Category B Requirements.** Component-leakpaths monitored quarterly at less than 500 ppmv shall achieve a mass emission control efficiency of 85 percent. Category B component-leakpaths are defined as components subject to enhanced fugitive inspection and maintenance programs for which screening values are also maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. Category B component-leakpaths also include component-leakpaths associated with closed vent systems (e.g., vapor recovery systems, and Subpart Kb and Subpart HH vessels) for which screening values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For Category B components, screening values above 500 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(viii) **Category C Requirements.** Component-leakpaths monitored quarterly at less than 100 ppmv shall achieve a mass emission control efficiency of 87 percent. Category C component-leakpaths are defined as component-leakpaths subject to enhanced fugitive inspection and maintenance programs for which screening values are also maintained at or below 100 ppmv as methane, monitored per EPA Reference Method 21. For such Category C components, screening values above 100 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(ix) **Category F Requirements.** Low-emitting design component-leakpaths monitored quarterly at less than 100 ppmv shall achieve a mass emission control efficiency of 90 percent. Category F component-leakpaths are subject to BACT per Rule 331 for which screening values are maintained at or below 100 ppmv as methane, monitored per EPA Reference Method 21. For such Category F components, screening values above 100 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(x) **Category J Requirements.** Low-emitting design component-leakpaths monitored quarterly at less than 500 ppmv shall achieve a mass emission control efficiency of 90 percent. Category J component-leakpaths are subject to BARCT per ATC 9047 and Rule 331 for which screening values are maintained at or below 500 ppmv as methane, monitored per EPA Reference Method 21. For such Category J components, screening values above 500 ppmv shall trigger the Rule 331 repair process per the minor leak schedule.

(xi) *Fugitive Emission Component BARCT Requirements* – In addition to the requirements specified in ATC 9047 to retrofit existing valves and connections during the expansion construction window, POPCO shall accomplish the following *Best Available Retrofit Control Technology* program to reduce and minimize fugitive hydrocarbon emissions from existing valves and connections that were permitted and/or were in service prior to the issuance of ATC 9047.

(1) Monitor all existing safe-to-monitor valves locations (whether retrofit to Category F or remaining a Category B valve) to a 500 ppmv minor leak threshold. Rule 331 protocol for repairing, removing from service or replacing minor leakers shall apply at this 500 ppmv threshold for Category B and J valves, and at the 100 ppmv threshold for the Category F valves;

(2) If a leaking Category B and/or Category J valve cannot be repaired to less than 500 ppmv, or is removed from service pursuant to Rule 331 protocols, that valve shall be irrevocably subject to retrofit as a Category F valve. The Category F retrofit shall be accomplished within one year from the date the repair does not restore the Category B valve to less than 500 ppmv leakage; and

(3) All Rule 331 BACT triggers apply to any valve not reduced to below 1,000 ppmv leakage.

(xii) *Pump Seals* – Any pump installed in hydrocarbon service shall be equipped with a double mechanical seal.

(c) <u>Monitoring</u>: The equipment listed in this section are subject to all the monitoring requirements listed in APCD Rule 331.F and NSPS Subpart KKK. The test methods in Rule 331.H and NSPS Subpart KKK shall be used, when applicable.

(i) *ERCs for Platform Heritage Low/Intermediate Pressure and High Pressure Projects* **-** POPCO shall perform quarterly monitoring on a minimum of 434 standard (i.e., non-bellows seal and non-low emissions) valves and a minimum of 1,302 standard flanges/connections at 100 ppmv leak detection threshold in order to generate 0.263 tpq of ROC ERCs of the total required for projects permitted by ATC 11132. These components will be listed in a separate table in POPCO's I&M Plan. POPCO shall replace any component on the list with a replacement if the component is no longer in hydrocarbon service. The APCD shall be notified, in writing, of all such replacements within ninety (90) days after the replacement. The notification shall include complete equipment description information equivalent to the table in POPCO's APCD approved I&M Plan and the reason for the replacement. Subsequent I&M records and reports shall include the replacement component(s).

(d) Recordkeeping: The equipment listed in this section is subject to all the recordkeeping requirements listed in APCD Rule 331.G and NSPS Subpart KKK. In addition, POPCO shall:

(i) *I&M Log* - POPCO 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 that exceeds the applicable limit :

(1) greater than 1,000 ppmv for minor leaks under Rule 331 (includes Accessible/Inaccessible components and Category A components);
(2) greater than 100 ppmv for components subject to current BACT (includes Bellows, Category F and Category G)
(3) greater than 100 ppmv for components subject to enhanced fugitive inspection and maintenance programs (Category C and Category E)
(4) greater than 500 ppmv for components subject to BARCT per ATC 9047 and/or enhanced fugitive inspection and maintenance programs (Category B, Category D, and Category J)

(ii) *BARCT* – POPCO shall record in a log all components that have been retrofit with BARCT per the requirements of 9.C.3.b(xi) above.

(iii) *Enhanced I&M* - For the 434 valves and 1,302 flanges/connections monitored quarterly at 100 ppmv as required by DOI 0034 and ATC/PTO 11130, maintain a record of information concerning leaks and repairs to include plant, P&ID number, tag number, component, measured emission rates (ppmv and drop-per-minute), date inspected, date of repair, days to repair, and re-inspection data and results. Further, maintain on a quarterly basis a record that all the valves were monitored in accordance with Permit Condition 9.C.3(c) above. The data will be made available to the District upon request.

(iv) *BARCT* - For valves monitored at 500 ppmv per ATC 9047, maintain a record of information concerning leaks and repairs to include plant, P&ID number, tag number, component, measured emission rates (ppmv and drop-per-minute), date inspected, date of repair, days to repair, and re-inspection data and results. Further, maintain on a quarterly basis a record that all the valves were monitored in accordance with Permit Condition 9.C.3(c) above. The data will be made available to the District upon request.

(e) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 331.G and NSPS KKK. POPCO shall provide an updated fugitive hydrocarbon component inventory due to changes in the component list or diagrams within one calendar quarter of any change, per Rule 331.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: ATC 9047, ATC 9047-4, ATC 9047-2, ATC/PTO 9471, ATC 9471-1, ATC 9487, ATC 9675 PTO 8092, ATC/PTO 11130*]

C.4 **Pigging Equipment.** The following equipment is included in this emissions category:

Device Type		POPCO ID	APCD DeviceNo
Pigging			
	Gas Pig Receiver	A-50	106398

(a) Emission Limits: With the exception of fugitive emissions from valves and connections, there are no permitted emissions allowed due to the opening and closing of the pig receiver. Compliance shall be based on the operational and monitoring limits of this permit.

(b) Operational Limits: Operation of the equipment listed in this section shall conform to the requirements listed in APCD Rule 325.E. In addition POPCO shall meet the following requirement:

(i) *Pig Openings* - Access openings to the pig receiver shall be kept closed at all times, except when a pipeline pig is being placed into or removed from the receiver. Prior to opening the pig receiver, POPCO shall completely purge the vessel with nitrogen to eliminate ROC compounds. Purged gases shall be sent to the gas plant's vapor recovery system.

(ii) *Vapor Recovery Use Required* – No pigging receiver gases shall be vented to the atmosphere, for combustion in the Utility Boilers B-801A/B or for combustion in the thermal oxidizer. All pigging receiver gases shall be vented either to the POPCO gas plant gas processing system, or to the PDS vapor recovery system.

(iii) *Blowdown Rate* – The rate in which gas from the pigging receiver can be blown down to the PDS vapor recovery system shall not exceed 10 SCF/min.

(c) Monitoring: POPCO shall monitor the blowdown rate from the pigging receiver using an APCD-approved flow meter.

(d) Recordkeeping: For each pigging event, POPCO shall record in a log the date, time, duration of the event, the blowdown rate and where the pigging and purge gases were directed.

(e) Reporting: none.[*Re: ATC/PTO 9471, ATC 9471-1, ATC 9047]*

C.5 **Tanks.** The following equipment is included in this emissions category:

Device Type		POPCO ID	APCD DeviceNo
Storage Tanks			
	Methanol Tank	T-111	102620
	Wastewater Tank	T-601	103103
	Wastewater Tank	T-807	103104

(a) Operational Limits: Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. The methanol tank listed in this section shall meet the requirements of APCD Rule 326, Sections D.1.a and, D.2.a. Wastewater tank T-601 shall be equipped with a control device that meets the requirements of Rule 325. Wastewater tank T-807 shall meet the requirements of APCD Rule 325, Section H. In addition, POPCO shall:

(i) *Throughput and Vapor Pressure Limits* – The following tank throughput and vapor pressure limits shall not be exceeded:

Tank Name	**Daily** (gal/day)	**Quarterly** (gal/qtr)	**Annual** (gal/yr)	**TVP** (psia)
Methanol Tank	10,500	10,500	10,500	1.9

(ii) *Wastewater Tank Carbon Canisters* – The date that carbon was last replaced in each carbon canister shall be visibly marked on the canister. The carbon shall be replaced: (a) within 24-hours when there are indications that the carbon it is not performing as designed (defined as any indication of sulfur compounds emanating from the canister vents), or (b) within one year of the last carbon replacement, whichever is sooner.

(b) Monitoring: POPCO shall:

(i) On a per shipment basis, monitor the amount and vapor pressure of methanol loaded into the tank.

(ii) On a weekly basis, POPCO shall monitor the carbon canister vents for any indication of sulfur compounds emanating from the canister vents.

(iii) Wastewater tank T-601 shall be monitored in accordance with Rule 325.G or other APCD approved procedures to ensure compliance with the control requirements of Rule 325.

(iv) Wastewater tank T-807 is currently out of service. POPCO shall source test tank T-807 within sixty (60) days of its next use according to the Source Testing condition in this permit, and then every two years thereafter. If any source test does not demonstrate T-807 qualifies for an exemption in Section B of Rule 325, POPCO shall comply with the control requirements of the rule.

(v) The source test condition 9.C.18 shall be adhered to, and the source test plan shall address the following items:

(1) A process description of the tank and the flows into the tank.
(2) Operational conditions during the test, and how they will be representative of worst-case operations/throughputs
(3) The duration of the test and how it will address breathing and working losses
(4) Measurement of tank inflow rates
(5) The procedure for determining lb/hr ROC emission rates

(c) Recordkeeping: The methanol tank listed in this section shall meet the requirements of APCD Rule 326, Sections I.3, J and K. The wastewater tanks shall meet the requirements of APCD Rule 325, Section F. In addition, POPCO shall maintain hardcopy records for the information listed below:

(i) For each methanol shipment log: the date of shipment, the product name and supplier, amount of methanol loaded.

(ii) Maintain a copy of each manufacturer's MSDS sheet that document's the vapor pressure of the product. Log all changes in supplier and keep a copy of the MSDS sheet with the log.

(iii) For each carbon canister adsorber, the date of carbon change-out and the quantity and type of carbon recharged to the canister shall be recorded monthly in a log.

(d) 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: PTO 8092, PTO 8092 Mod-03*]

C.6 **Solvent Usage.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
Solvent Usage		
Cleaning/Degreasing		8662

(a) Emission Limits: Mass emissions from the solvent usage shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance shall be based on the 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 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, POPCO 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* - POPCO shall abide by the procedures identified in the APCD approved Solvent Reclamation Plan that describes the proper disposal of any reclaimed solvent. All solvent disposed of pursuant to the APCD approved Plan will not be assumed to have evaporated as emissions into the air and, therefore, will not be counted as emissions from the source. The Plan details 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.

(v) *BACT* – POPCO shall implement the following BACT measures for solvent use at the facility: Use of Low-VOC or water-based solvents, where feasible. POPCO shall provide the APCD a list of all solvents (both BACT and non-BACT) used at the facility, the properties and general equipment and/or processes the solvents are used on. At the request of the APCD, POPCO shall provide the APCD the reason why it is not feasible to use BACT defined solvents for specific situations. This solvent list is hereby incorporated by reference as an enforceable part of this permit.

(c) Monitoring: none

(d) Recordkeeping: POPCO 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; and the amount of solvent reclaimed for APCD-approved disposal according to the APCD-approved Solvent Reclamation Plan. Based on the APCD approved Solvent Reclamation Plan, POPCO shall also record 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 LFC.

(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: ATC 9047-4]

C.7 **Sulfur Recovery Unit/Stretford Tailgas Unit.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
Sulfur Removal Unit		
Claus Plant		105162
Beavon Plant		105183
Stretford Tailgas Unit		105204

(a) Emission Limits: Except for startup and shutdown operations as defined in Table 4.5, mass emissions from the Sulfur Recovery Plant ("SRU") and Tailgas Unit shall not exceed the limits specified in Tables 5.3, 5.4 and 5.5. During startup and shutdown operations, the emissions of SO_x (as SO_2) from the SRU listed as (*Combined B-801 A/B Stack Emissions)* shall not exceed the limits as listed in Table 5.5. Compliance shall be based on sliding-one hour readings of 15-minute averages (or less) through the use of process monitors (e.g., fuel use meters) and CEMS; and the monitoring, recordkeeping and reporting condition of this permit. For pollutants without CEMS monitors, the permitted emission factors in Table 5.2 shall be used. In addition, the following specific emission limits apply:

(i) *BACT* – Except during startup and shutdown operations as defined in Table 4.5, the emissions, after control, from the SRU shall not exceed the BACT limits listed below and in Table 4.5 (*BACT. Sulfur Recovery Unit (SRU)*). Compliance shall be based on the use of process monitors, analyzers and CEMS as detailed in Table 4.5 and Table 4.9 as well as annual source testing for all pollutants. Compliance with the efficiency limit shall be based on a twenty-four (24) hour average; compliance with the concentration limits shall be determined via the DAS on a six-minute basis. Compliance for the SO_x shall also be based on the APCD-approved Sulfur Removal Efficiency Plan.

BACT for the Removal of H_2 S through the SRU	
Operational Mode	**Removal Efficiency (% by mass as H_2S)**
All SRU Inlet Feed Rates to 60 LTD [k]	✓ The more stringent of: i) 99.9% H_2S by mass across SRU; or ii) 100 ppmvd residual H_2S in Stretford Tailgas;
	and
	✓ No more than 2.89 lb/hr H_2S in Stretford Tailgas [l] (5.44 lb/hr SO_2 equivalent emissions @ boiler stacks)

[k] Expressed as long tons per day ("LTD") of total elemental sulfur mass based on H_2S (only) in the acid gas feed to the SRU. This is a calculated value using the POPCO sour gas inlet feed gas H_2S analyzer (AI-172) and the sour gas feed volume meter (FIC-1). All plant inlet H_2S is assumed to be fed to the SRU.

[l] As measured by the calibrated Stretford Tailgas H_2S analyzer (AI-405) and Tailgas volumetric flow meter (FI-405).

(ii) *NSPS Subpart LLL* – Per 40 CFR 60.642(b), POPCO shall comply with the SO_2 emission reduction efficiencies as listed below and in Table 2 of the Subpart. Compliance with this Subpart shall be based on the monitoring, recordkeeping and reporting requirements of this permit, the APCD-approved Sulfur Removal Efficiency Plan, and NSPS Subpart LLL. Ongoing compliance requirements with this NSPS are summarized in Table 4.17. The Subpart LLL efficiency limits are enforced on a daily basis (24-hour average).

NSPS LLL for the Removal of Total Reduced Sulfur Removal by SRU	
Operational Mode	**Removal Efficiency (% by mass total sulfur)** [m]
≤ 20 LTD [n]	✓ 98.0
>20 LTD to 60 LTD [o]	✓ 99.9
Or	
At any SRU throughput	✓ No more than 5.67 lb/hr SO_2 emissions from Combined B-801A&B Stacks [o]

(b) Operational Limits: All process operations from the equipment listed in this section shall meet the requirements of APCD Rule 311.A.2, the BACT requirements listed in Tables 4.5 and 4.6, and the requirements of NSPS Subpart LLL. Compliance with these limits shall be assessed through compliance with the monitoring, recordkeeping and reporting conditions in this permit. In addition, POPCO shall:

(i) TGU Off Gas Input Limits – POPCO shall comply with the following usage limits (HHV based):

(1) TGU Off Gas to Boilers B-801A/B: 5.620 MMBtu/hr; 135 MMBtu/day; 12,308 MMBtu/quarter; 49,231 MMBtu/year

(ii) Compliance shall be based on the monitoring, recordkeeping and reporting requirements of this permit. POPCO shall use the most recent heating value analysis in conjunction with the TGU off gas meter readings to calculate the heat input to the boilers.

(iii) *Sulfur Removal Unit Failure Mitigation System* –To comply with the POPCO expansion FDP, Condition E-5, and to eliminate the potential localized violation of the SO_2 ambient air quality standard which could occur from flaring acid gas generated during a SRU shutdown event, POPCO shall permanently install and operate an automatic shutdown system into the V-204 Sulfinol Stripper to prevent flared acid gas volumes in excess of 1480 SCF. This automatic shutdown system, and required equipment is fully described in POPCO's July 15, 1996 letter to the APCD, "Final Unplanned Flaring SO2 Impact Modeling Report and Mitigation"; ATC Permit Application #9047.

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[m] TRS removal efficiency across SRU is defined as the percent reduction of the plant inlet elemental sulfur in LTD (based on H_2S only) from the elemental sulfur emitted to the atmosphere as measured by the boiler stack SOx CEMS.

[n] See footnote "l" above.

[o] SO_2 emissions in combined boiler stacks (including incineration fuel sulfur) as measured by the boiler stack SO_x CEM system.

(iv) To ensure the effectiveness of this system, POPCO shall implement the APCD-approved *SRU Failure Mitigation System Test Plan* for the life of the project. The Plan identifies and documents the procedures and testing protocol of this mitigation system, such that the test confirms, in the event of an actual SRU failure, no excess acid gas releases to the ZTOF shall occur at or below the maximum design SRU acid gas feed rate of 60 LTD of H_2S. Any SRU failure that activates this shutdown system shall be documented according to the reporting requirements of this permit (*SRU Shutdown Report*). The performance of this system shall be jointly evaluated by the APCD and POPCO after each incident of its use, or other APCD-specified frequency.

(v) *Minimum Boiler Incineration Temperature* – The average daily temperature of the gas leaving the boiler's combustion zone when tailgas is being incinerated shall be at or above 919 °F at all times. Compliance shall be based on at least 96 evenly spaced measurements of the combustion zone temperature over each 24 hour period and telemetry of that data to the APCD's DAS.

(1) POPCO may request that the minimum incinerator temperature be reestablished by conducting new performance tests under §60.8 of 40 CFR 60.

(c) <u>Monitoring</u>: POPCO shall monitor the emission and process parameters listed in Tables 4.9 through 4.12 for the life of the project. POPCO shall perform annual source testing of the SRU consistent with the requirements listed in Table 4.14 and the source testing permit condition below. In addition, POPCO shall:

(i) *Process Monitors* – POPCO shall install and maintain in-plant process monitors as shown in Figure 4.1 and Table 4.9 for the life of the project.

(ii) *Stretford Unit Oxidizer Tanks* – To ensure that hydrocarbon emissions associated with carry-under of hydrocarbons from the Beavon Tailgas into the Stretford unit oxidizers are within permitted limits, POPCO shall source test the tanks on a triennial basis. The source test plan for this test shall include, but not necessarily be limited to the following parameters:

(1) Stretford oxidation air flow rates (i.e., inlet air to oxidation tanks);
(2) Bag samples of representative air flow emanating from the oxidizer tanks;
(3) Analysis of bag samples for reactive hydrocarbon speciation to C6+;
(4) A calculation of the apparent mass of reactive hydrocarbons emitted to the atmosphere from the oxidation tanks (lb/hr and tons/yr);
(5) Data on the Stretford solution and Beavon Tailgas temperatures where the solution contacts Beavon Tailgas; and
(6) The total Stretford Tailgas flow rate to the Utility Boilers.

(d) <u>Recordkeeping</u>: POPCO shall record the emission and process parameters listed in Tables 4.9 through 4.12. In addition, POPCO shall maintain the following:

(i) *Sulfur Recovery Unit/Stretford Tailgas Unit Report*– On a daily basis through the DAS:

(1) Inlet sour gas volume treated;

(2) The maximum H_2S concentration in sour gas inlet to the plant; and through written records;
(3) Amount of H_2S processed (LTD) through SRU;
(4) The percent H_2S reduction across the SRU;
(5) The percent total sulfur reduction across the SRU;
(6) The maximum H_2S mass flow rate (lb/hr) in the Stretford tailgas;
(7) The maximum Stretford tailgas H_2S concentration;
(8) The amount of sulfur production (LTD) (both Stretford and molten elemental sulfur production).
(9) The maximum peak SO_2 emission rate (lb/hr) from the combined Process Boiler stacks;
(10) The total SO_2 emissions (in lb/day) from the combined Process Boiler stacks.

(ii) *Inlet Sour Gas Feed H_2S Analyzer* – In the event that the inlet analyzer is non-operational for more than twenty four hours and deviations of permitted limits occur POPCO shall submit the sampling results and associated calculations for the data that would have been submitted through the DAS as defined in condition 9.C.7.d.i and ii with the deviation report.

(1) If no deviations occur during the period in which the back-up sampling method is used, the data that would have been submitted through the DAS will be included in the semi-annual compliance verification report with an asterisk denoting the dates in which the back-up sampling method was used.

(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: ATC 9047, ATC 9047-2, ATC 9047-4, PTO 8092*]

C.8 **Facility Throughput Limitations.** The POPCO gas processing facility shall be limited to the following processing limits:

(a) *60 MMSCFD Throughput Limit*: The volume of inlet sour gas to the plant containing a maximum of 26,700 ppmv (2.67%) H_2S shall not exceed 60 million standard cubic feet per calendar day. Compliance shall be based on the use of CEMS/DAS (daily average based on 6-minute average), process meters, lab analyses and field measurements;

(b) *80 MMSCFD Throughput Limit*: The volume of inlet sour gas to the plant containing a maximum of 7,000 ppmv (0.7%) H_2S shall not exceed 80 million standard cubic feet per calendar day. Compliance shall be based on the use of CEMS/DAS (daily average based on 6-minute average), process meters, lab analyses and field measurements;

(c) *Molten Sulfur Production Limit*: Maximum production of 60 long tons of molten sulfur on any given day;

(d) *Inlet Sour Gas H_2S Limits*: At no time shall the concentration of H_2S in the inlet sour gas to the plant exceed 26,700 ppmv (2.67%). In addition, when the inlet sour gas *rate* to the plant exceeds 60 MMSCFD, the concentration of H_2S in the inlet sour gas to the plant shall not exceed 7,000 ppmv (0.7%). Compliance shall be based on use of CEMS/DAS (6-minute average), process meters, lab analyses and field measurements. The *gas rate* applies on a 6-minute average; and

(e) Sour Gas Pipeline Throughput Limit: The offshore-to-onshore sour gas pipeline shall be limited to a maximum throughput of 90 MMSCFD; up to 80 MMSCFD of sour gas can be processed at the POPCO facility and up to 15 MMSCFD of sour gas can be processed at ExxonMobil's Stripping Gas Treating Plant (after being transported via the sour gas pipeline interconnect). The combined total throughput of both the volume of sour gas to the POPCO plant and the interconnect sour gas pipeline to the Stripping Gas Treating Plant shall not exceed a maximum of 90 MMSCFD at any time.

(f) POPCO shall track in a log, on a daily basis, the actual usage data of the parameters limited by this condition (using an APCD-approved format). [*Re: ATC 9047, ATC 9047-2, ATC 9047-5, PTO 8092*]

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 POPCO facility. These records or logs shall be readily accessible and be made available to the APCD upon request. During this five year period, and pursuant to California Health & Safety Code Sections 42303 and 42304, such data shall be available to the APCD at the POPCO facility within a reasonable time period after request by the APCD. This requirement applies to data required by this permit and archived by POPCO's data-storage systems including but not limited to charts and manual logs. With the exception of CEMS data, prior to archiving any required data from the data-storage system, POPCO shall prepare written reports and maintain these reports in 3-ring binders at the POPCO facility. CEMS data shall be kept consistent with the requirements of POPCO's APCD-approved CEMS Plan. Failure to make such data available within the noted period shall be a violation of this condition. Further, retrieval of historical or archived data shall not jeopardize the logging of current data. [*Re: ATC 9047, PTO 9047*]

C.10 **Compliance Verification Reports.** Twice a year, POPCO 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 by March 1st and September 1st each year. 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, a completed *APCD Annual Emissions Inventory* questionnaire should be included in the annual report or submitted electronically via the APCD website. POPCO 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 POPCO 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) *External Combustion.*

(1) The Boiler Fuel Gas Usage: For each utility boiler, the daily, quarterly and annual fuel use in units of million Btu and standard cubic feet. In addition, the five highest hourly heat input rates per month in units of million Btu/hr for each utility boiler.

(2) TGU Off Gas Usage: For each utility boiler, the daily, quarterly and annual amount of TGU off gas combusted in the boiler in units of million Btu and standard cubic feet. In addition, the five highest hourly heat input rates per month in units of million Btu/hr.

(3) Boiler Fuel Gas Data: Results of the weekly sorbent tube readings of H_2S and the quarterly analyses of H_2S, total sulfur compounds and high heating value. Include copies of the quarterly lab analyses.

(4) Sales Fuel Gas Data: Results of the highest weekly reading observed from the H_2S analyzers and the quarterly analyses of H_2S, total sulfur compounds and high heating value. Include copies of the quarterly lab analyses.

(5) TGU Off Gas Data: Results of the quarterly analyses of high heating value. Include copies of the quarterly lab analyses.

(6) Source Testing: Summary results of all compliance emission source testing performed including information required by APCD Rule 342.J and Table 4.10.

(b) *Thermal Oxidizer*.

(1) Volumes/Mass Emissions: The volumes of gas combusted and resultant mass emissions for each flare category (i.e., Purge; Pilot; Continuous – HC/AG Header Baseline System Leakage; Continuous – AG Header Compressor Seal Leakage; Planned Other; and, Unplanned Other) shall be presented as a cumulative summary for each day, quarter and year. The report shall clearly indicate the basis for each data point presented, including supporting data for the baseline system leakage calculations.

(2) Volumes/Mass Emissions - Unplanned: The volumes of gas combusted and resultant mass emissions for each Unplanned Other flaring event. Include: the date, start time, duration, volume, H_2S and total sulfur content, HHV, specific reason/cause for flaring and the APCD Rule 505 breakdown number and/or Variance Order number. The report shall clearly indicate the basis for each data point presented.

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

(4) The highest total sulfur content and hydrogen sulfide content observed each week in the HC header, Acid Gas header, Sale Gas line and Boiler Fuel Gas line.

(5) A copy of Flare Event Log for the reporting period. Include a separate listing of all planned infrequent events that occurred more than four times per year from the same cause from the same processing unit or equipment type.

(6) Monthly Volumes Flared: A summary of the total amount of gas flared at the facility for each month for all planned flaring (event and non-events).

(7) Any other information required by APCD Rule 359.H.

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

(1) Inspection summary which includes a record of the total components inspected and the total number and percentage found leaking by component type, inspection frequency, and leak detection threshold (i.e. the component "Category" as defined in Permit Guideline Document 15).

(2) Record of leaking components (including name, location, type of component, date of leak detection, the ppmv or drop-per-minute reading, date of repair attempts, method of detection, date of re-inspection and ppmv or drop-per-minute reading following repair) and associated component repair actions including dates of component re-inspections. The report shall clearly identify the corresponding leak thresholds for each component category (i.e., Category A, Category B, etc.). The record shall also specify leaks from critical components.

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

(4) Listing of components installed as BACT under Rule 331 or the BACT requirement of Condition C.31, during the reporting year as approved by the APCD.

(5) Any other information required by APCD Rule 331.G and NSPS Subpart KKK.

(d) *Pigging*. The number of pigging events per quarter and per year along with a copy of the pigging log.

(e) *Tanks*.

(1) For each methanol shipment log: the date of shipment, the product name and supplier, amount of methanol loaded.

(2) The frequency of carbon change-out and the quantity and type of carbon recharged to the adsorbers.

(f) *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.

(g) *Sulfur Recovery Unit/Stretford Tailgas Unit*.

(1) Sulfur Recovery Unit/Stretford Tailgas Unit Report (on a daily basis Through the DAS):

i inlet sour gas volume treated;
ii amount of H_2S processed (LTD) through SRU;
iii the maximum H_2S concentration in sour gas inlet to the plant; and through written records;
iv the amount of sulfur production (LTD) (both Stretford and molten elemental sulfur production);
v the percent H_2S reduction across the SRU;
vi the maximum H_2S mass flow rate (lb/hr) in the Stretford tailgas;
vii the maximum Stretford tailgas H_2S concentration;
viii the percent total sulfur reduction across the SRU;
ix the maximum peak SO_2 emission rate (lb/hr) from the combined Utility Boiler stacks; and
x the total SO_2 emissions (in lb/month) from the combined Utility Boiler stacks.

(2) SRU shutdown report (for any unplanned shutdowns include the date, shutdown time start, cause for shutdown, and estimated SRU acid gas volumes sent to the flare).

(3) Any other information required by NSPS Subpart LLL.

(h) *Facility Throughput Data*.

(1) The inlet rate of sour gas to the gas plant per day in units of million standard cubic feet.

(2) The highest recorded hydrogen sulfide content (ppmv) of the inlet sour gas on a daily basis.

(3) The annual average value of inlet sour gas to the gas plant in units of million standard cubic feet.

(4) The amount of sour gas transported in the offshore-to-onshore sour gas pipeline on a daily basis in units of million standard cubic feet.

(i) *General Reporting Requirements*.

(1) On quarterly basis, the emissions from each permitted emission unit for each criteria pollutant (along with the appropriate supporting data). The fourth quarter report shall include tons per year totals for all pollutants, by each emission unit and totaled.

(2) On quarterly basis, the emissions from each exempt emission unit including CARB certified equipment used at the facility, for each criteria pollutant (along with the appropriate supporting data). The fourth quarter report shall include tons per year totals for all pollutants, by each emission unit and totaled.

(3) POPCO shall submit with each required semi-annual report two quarterly CEMS Reports. The CEMS Reports shall follow the format and provide the information detailed in the APCD-approved CEMS Plan.

(4) A summary of each and every occurrence of non-compliance with the provisions of this permit, APCD rules, NSPS and any other applicable air quality requirement with the excess emissions that accompanied each occurrence.

(5) Information as required by the APCD-approved *Fuel Gas and HHV Reporting Plan*.

(6) Process stream analyses report (for Section 4.12.2 requirements).

(7) Maintenance and Calibration: Summary of all maintenance and calibration activities/logs performed on the utility boilers, thermal oxidizer, emission control systems, process meters, H_2S analyzers and CEMS.

(8) The monthly summary of the total volume (e.g., gallons) of NGL transferred from POPCO to the ExxonMobil facility shall be recorded and reported to the APCD.

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

[*Re: PTO 8092, ATC 9047ATC 9047-4, PTO 9215, ATC/PTO 9471, ATC 9487, ATC 9675, ATC 9693]*

C.11 **BACT.** POPCO shall apply emission control and plant design measures which represent Best Available Control Technology (BACT), to the operation of the POPCO Gas Plant facilities as described in Section 4.10 and Tables 4.1, 4.2, 4. 3, 4. 4, 4. 5, 4. 6, 4.7, and 4.8 of this permit, as well as permit conditions C.2, C.3, C.6 and C.7 herein. BACT measures shall be in place and in operational at all times for the life of the project. [*Re: ATC 9047, ATC 9047-4*]

C.12 **Continuous Emission Monitoring ("CEM").** POPCO shall implement a CEM program for emissions and process parameters as specified in Section 4.11 and Tables 4.9 through 4.12 of this permit. POPCO shall implement the APCD-approved CEM Plan. The CEM monitors shall be in place and functional for the life of the project. The APCD shall use the CEM data alone, or in combination with other data, to verify and enforce project conditions. Excess mass emissions indicated by the CEM systems shall be considered a violation of the applicable mass emission limits.

(a) The monitoring devices shall meet the requirements set forth in APCD Rule 328 and 40 CFR 51 and 40 CFR 60. Monitors must be installed, maintained, and operated in accordance with APCD and EPA requirements, as specified in the CFR and the APCD-approved CEM Plan and with manufacturer's specifications.

(b) Performance certification (relative accuracy testing and seven day calibration drift test) of the boiler SO_x & NO_x, inlet feed H_2S and Stretford Tailgas H_2S analyzers shall occur at least once per year, or more often if determined necessary by the APCD. POPCO shall perform quarterly quality assurance audits as per 40 CFR 60, Appendix F on these analyzers. Additional continuous monitors or redundant systems may be required by the

APCD if problems with the facility or the continuous monitors develop which warrant additional monitoring.

(c) The required data will be consolidated and submitted to the APCD within forty-five (45) days after the close of each calendar quarter. More frequent reporting may be required if deemed necessary by the APCD. Minimum data reporting requirements shall be consistent with APCD Rule 328 and the approved CEM Plans and (as a minimum) must include the following:

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

(d) In addition, operator log entries, strip charts, magnetic tapes, computer printouts, circular charts or diskettes, whichever is applicable, shall be provided upon request to the APCD.

(e) Pursuant to California HS&C §42706, POPCO shall report all emission exceedances detected by the CEMS to the APCD within 96 hours of each occurrence.

(f) POPCO shall maintain and operate continuous in stack monitoring equipment for the mass emissions (lb/hr basis) of nitrogen oxides (as NO_2) and sulfur oxides (as SO_2) from each Utility Boiler (B-801 A and B). POPCO shall compute and telemeter the sliding hourly average for nitrogen oxide emissions (lb/hr) and sulfur oxide emissions (lb/hr) individually from Utility Boiler B-801 A and B.

(g) *Inlet Sour Gas Feed H_2S Analyzer* – POPCO shall continuously monitor the inlet sour gas H_2S content per 40 CFR 60.646. In the event that the inlet analyzer is non-operational for more than twenty four (24) hours POPCO will follow the APCD-approved back-up sampling protocol defined in the updated APCD-approved CEM Plan. [*Re: PTO 8092, ATC 9047, PTO 9215*]

C.13 **Data Telemetry.** POPCO shall telemeter monitoring data to the APCD as specified by Conditions C.12 (*Continuous Emission Monitoring*) and C.16 (*Ambient Air Quality and Odor Monitoring Program*) of this permit. The data telemetry equipment shall be in place and functional for the life of the project consistent with the above-specified conditions. This telemetry equipment shall be compatible with the APCD's Central Data Acquisition System. Table 9.1 (*CEMs Parameters To Be Telemetered To The Data Acquisition System (DAS)*), defines the parameters required to be telemetered to the DAS (excluding Ambient Air Quality and Odor Monitoring Program data). [*Re: PTO 8092, PTO 9215*]

Table 9.1 CEMs Parameters to be Telemetered to the DAS

DAS Variable	Parameter Monitored
INGASFLO	Sour Gas Inlet Flow Rate
INGASH2S	Mole % H2S in Sour Gas Feed
TAILH2S	H2S from Stretford Unit
ATGGLOW	Flow Volume from Stretford Unit to B-801A
ABTGFLOW	Flow Volume from Stretford Unit to B-801B
ABSO2LB	Combined SOx Stack Emissions
ASO2LB	Boiler A SO_x (lb/hr)
BSO2LB	Boiler B SO_x (lb/hr)
ATEMP	Boiler A Combustor Zone Temp
BTEMP	Boiler B Combustor Zone Temp
ANOXLB	Boiler A NOx (lb/hr)
BNOXLB	Boiler B NOx (lb/hr)
AFUELGAS	Fuel Flow to Boiler A
BFUELGAS	Fuel Flow to Boiler B
AGHDRFLO	Acid Gas Flare Flow Rate
HCHEADER	HC Flare Flow Rate
SALEH2S2	Sales Gas H2S

Notes
1 NO_x as NO_2; SO_x as SO_2

C.14 **Central Data Acquisition System.** This system shall receive and analyze continuous emissions data from POPCO CEMs (as specified in Condition C.12), and odor monitoring (as specified in Condition C.16) and any other data necessary to evaluate observed and potential air quality impacts either site-specific or regional. [*Re: ATC 9047, PTO 8092, PTO 9215, ATC 9047-3*]

C.15 **Central Data Acquisition System Operation and Maintenance Fee.** By permit conditions C.12 and C.16, POPCO shall connect certain Continuous Emission Monitors (CEM) and all ambient, meteorological, and odor parameters to the APCD central data acquisition system (DAS). In addition, POPCO shall reimburse the APCD for the cost of operating and maintaining the DAS. POCPCO shall be assessed an annual fee, based on the APCD's fiscal year, collected semi-annually.

(a) Pursuant to Rule 210 III.A, POPCO shall pay fees specified in Table 9.2. The APCD shall use these fees to operate, maintain, and upgrade the DAS in proper running order. Fees shall be due and payable pursuant to governing provisions of Rule 210, including CPI adjustments.

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

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

Table 9.2 Fees for Data Acquisition System (DAS) Operation and Maintenance

FEE DESCRIPTION	FEE
Per CEM, ambient or meteorological parameter required by permit to be transmitted real-time to the APCD Central Data Acquisition System	$1,307 annually

(b) All ongoing costs and anticipated future capital upgrades will be APCD's responsibility and will be accomplished within the above stated DAS fee. This fee is intended to cover the annual operating budget and upgrades of the DAS and is intended to gradually phase APCD into a share of the DAS costs {as outlined in the APCD's March 27, 1998 letter (*Fixed Fee Proposal for Monitoring and DAS Costs*)}. In the event that the assumptions used to establish this fee change substantially, the APCD may revisit and adjust the fee based on documentation of the cost of services. Adjusted fees will be implemented by transmitting a revised Table 9.2.

(c) The fees prescribed in this condition shall expire if and when the Board adopts a Data Acquisition System Operation and Maintenance Fee schedule and such fee becomes effective. [*Re: ATC 9047-3, PTO 8092-1*]

C.16 **Ambient Air Quality and Odor Monitoring Program.** POPCO shall implement the following requirements:

(a) *Odor Monitoring Plan* – Implement the APCD-approved *Odor Monitoring Plan* (approved 9/13/93) for ambient odor monitoring and human olfactory verification programs for the life of the POPCO project.

(b) *Odor Monitoring Station* – Operate an odor monitoring station as listed in Sections 4.14 and 6.6 and Table 4.16 of this permit to continuously monitor ambient hydrogen sulfide (H_2S) concentrations to ensure that H_2S emissions emanating from the facility are in compliance with State and local ambient air quality standards and not causing a public nuisance. This station shall be located at the property boundary of the ExxonMobil LFC facility at a site approved by the APCD. For the purpose of compliance with APCD Rule 310 and the applicable ambient air standards, this odor monitoring station shall be assumed to be located at POPCO's property boundary. POPCO shall take over the maintenance and operation of the *LFC - Odor* station in the event ExxonMobil abandons or ceases to operate it. All monitoring equipment (H_2S and meteorological) shall be operated and maintained according to the *Air Quality and Meteorological Monitoring Protocol for Santa Barbara County*, dated October 1990, and all subsequent revisions. POPCO shall monitor and report the parameters listed in Table 4.16 in accordance with their APCD-approved Odor Monitoring Plan. All ambient monitoring data and records shall be submitted to the Air Pollution Control APCD in a form approved by the Air Pollution Control Officer. All data specified in Table 4.16 shall be telemetered to the APCD's Data Acquisition System on a real-time basis. Other odor-related pollutant-specific equipment may be added to the station, if deemed necessary by the APCD.

POPCO shall reimburse the APCD's costs for the review and audit of the station's data in accordance with the cost reimbursement provisions of Rule 210.

(c) Up to two additional monitors may be required of POPCO to monitor odorous emissions emanating from the Las Flores Canyon facilities and offshore operations if the APCD determines that odor thresholds are being exceeded. [*Re: PTO 8092, ATC 9047, ATC 9047-3*]

C.17 **Offsets and Consistency with the Clean Air Plan.** POPCO shall comply with all the procedures and requirements specified in Section 7 of this document including all requirements for offsets, source testing and reporting (if applicable). POPCO shall provide the following offsets:

(a) POPCO shall offset the net emission increase (NEI) resulting from operation of the Las Flores Canyon facility as detailed in Section 7 and Tables 7.1, 7.2, 7.3 and 7.4.

(b) If offsets are not in place as required by this permit, POPCO shall provide replacement offsets and shall obtain variance relief. [*Re: ATC 9047-4*]

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

(a) POPCO shall conduct source testing of air emissions and process parameters listed in Section 4.12 and Tables 4.13, 4.14, and 4.15 of this permit. More frequent source testing may be required if the equipment does not comply with permitted limitations or if other compliance problems, as determined by the APCD, occur. Source testing shall be performed at the frequency specified in Table 4.13 using May-June as the anniversary date for the utility boilers and the SRU. The first semi-annual test of the POPCO boilers shall be completed in December 2009.

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

(c) Source test results shall be submitted to the APCD within forty-five (45) calendar days following the date of source test completion and shall be consistent with the requirements approved within the source test plan. Source test results shall document POPCO's compliance status with BACT requirements, mass emission rates in Section 5 and applicable permit conditions, rules and NSPS. All APCD costs associated with the review and approval of all plans and reports and the witnessing of tests shall be paid by POPCO as provided for by APCD Rule 210.

(d) A source test for an item of equipment shall be performed on the scheduled day of testing (the test day mutually agreed to) unless circumstances beyond the control of the operator prevent completion of the test on the scheduled day. Such circumstances include mechanical malfunction of the equipment to be tested, malfunction of the source test equipment, delays in source test contractor arrival and/or set-up, or unsafe conditions on site. Except in cases of an emergency, the operator shall seek and obtain APCD approval before deferring or discontinuing a scheduled test, or performing maintenance on the equipment item on the scheduled test day. Once the sample probe has been inserted into the exhaust stream of the equipment unit to be tested (or extraction of the sample has begun), the test shall proceed in accordance with the approved source test plan. In no case shall a test run be aborted except in the case of an emergency or unless approval is first obtained from the APCD. If the test cannot 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. If a test is postponed due to an emergency, written documentation of the emergency event shall be submitted to the APCD by the close of the business day following the scheduled test day.

(e) The inlet feed gas flow meters (FY1 and FT-196) and the tail gas flow meters (FT-817A and FT-831A) for the SRU, and the plant meters Ft-448 and FT-493 for the Stretford oxidizer tanks shall have been calibrated no more than two (2) months prior to the test. The calibration certificates shall be provided to the APCD at least three (3) days prior to the test.

(f) Gas sampling and flow measurement for the inlet feed gas flow and the tail gas flow shall be performed simultaneously for determining H_2S efficiency for the SRU.

(g) Calculations of H_2S efficiency for the SRU and ROC emission rates for the Stretford oxidizer tanks shall be documented in the test report.

(h) The timelines in (a), (b), and (c) above may be extended for good cause provided a written request is submitted to the APCD at least three (3) days in advance of the deadline, and approval for the extension is granted by the APCD. [Re: ATC 9047, PTO 9215, ATC 9693]

C.19 **Process Stream Sampling and Analysis.** POPCO shall sample and analyze the process streams listed in Section 4.12.2 of this permit consistent with the requirements of that section. All process stream samples shall be taken according to APCD-approved ASTM methods/procedures and must be follow traceable chain of custody procedures. POPCO shall maintain logs and records documenting the results from all process stream analyses (in a format approved by the APCD). [*Re: ATC 9047*]

C.20 **Process Monitoring Systems - Operation and Maintenance.** All facility process monitoring devices listed in Section 4.11.2 of this permit shall be properly operated and maintained according to manufacturer recommended specifications. POPCO shall implement the APCD approved Process Monitor Calibration and Maintenance Plan for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules. Where manufacturer guidance is not available, the recommendation of comparable equipment manufacturers and good engineering judgment is utilized. [*Re: ATC 9047*]

C.21 **Fuel Gas Sulfur and HHV Reporting Plan.** POPCO shall implement the APCD-approved *Fuel Gas Sulfur and HHV Reporting Plan* for the life of the project. This Plan shall detail for each unique fuel supply: the monitoring equipment (and CEM protocol procedures if applicable), 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. At a minimum, the non-H_2S total sulfur adjustment shall occur on a quarterly basis. POPCO shall maintain records of the daily fuel gas analyses in a log (using an APCD-approved format).

C.22 **Abrasive Blasting Equipment.** All abrasive blasting activities performed at the POPCO facility shall comply with the requirements of the California Administrative Code Title 17, Sub-Chapter 6, Sections 92000 through 92530. [*Re: ATC 9047*]

C.23 **Vacuum Truck Use.** During vacuum truck use, POPCO shall use an APCD-approved control device (i.e., carbon adsorption system or equivalent) to reduce emissions of reactive organic compounds (ROC) and odorous compounds from the vacuum truck vent. POPCO shall maintain a log of all vacuum truck operations. The log shall include for each use, the date, the location and equipment ID where vacuum truck operations occur, volume and description of material, reason for use, duration of the operation and any emission control maintenance activities. POPCO shall implement ExxonMobil's LFC APCD-approved Vacuum Truck Operation & Maintenance Procedures Plan. The APCD-approved Plan is an enforceable part of this permit. Except for non-hazardous wastewater, for each vacuum truckload transported offsite, the date of use, the quantity (bbl or gal) and type of fluid handled shall be recorded. [Re: ATC 9047-4, PTO 8092]

C.24 **Emergency Firewater Pump/Electrical Generator IC Engines.** The following equipment are included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
Diesel Internal Combustion Engines		
Firewater Pump	P-805	2359
Firewater Pump	P-806	2356
Emergency Generator	G-800	2358
Emergency Air Generator	K-802	105147

(a) Operational Limits:

(i) Each engine shall be equipped with a non-resettable hour meter. POPCO shall not test these emergency engines concurrently with the testing of any emergency engine at ExxonMobil's LFC oil and gas plant.

(ii) *Particulate Matter Emissions:* To ensure compliance with APCD Rules 205.A, 302, 305, 309 and the California Health and Safety Code Section 41701, POPCO shall implement manufacturer recommended operational and maintenance procedures to ensure that all project diesel-fired engines minimize particulate emissions. POPCO shall implement the APCD-approved *IC Engine Particulate Matter Operation and Maintenance Plan* for the life of the project. This Plan details the manufacturer recommended maintenance and calibration schedules that POPCO will implement.

Where manufacturer guidance is not available, the recommendations of comparable equipment manufacturers and good engineering judgment shall be utilized.

(b) Recordkeeping: POPCO shall maintain records as required by Rule 333 Section H. Copies of all engine inspection and maintenance logs shall be retained onsite for at least two years after the date of the last entry and shall be made available to the APCD upon request:

(i) Hours of operation each month for each engine;

(ii) POPCO shall maintain an operating log detailing for each use: the start and stop times, the duration of use, the reason for use, the aggregate number of minutes each pump is operated quarterly and annually;

(iii) POPCO shall maintain an operating log detailing for each use: the start and stop times, the duration of use, the reason for use, the aggregate number of hours each engine is operated annually. This log shall be available for APCD review.

(c) Reporting: The equipment listed in this section are subject to all the reporting requirements listed in APCD Rule 333.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 as well as the information required by and Section H of Rule 333. [*Re: ATC 9047*]

C.25 **Produced Gas and Purging of Vessels.** POPCO shall direct all produced gases to the sales compressors, vapor recovery, the flare header or other permitted control device when de-gassing, purging or blowing down any tank, vessel or container that contains reactive organic compounds or reduced sulfur compounds due to activities that include, but are not limited to, process or equipment turnarounds, process upsets or agency ordered safety tests. [*Re: ATC 9047*]

C.26 **Natural Gas Liquids (NGL).**

(a) *NGL Loading Rack* – The NGL loading rack shall be equipped with a vapor return system. Such vapor return system shall be capable of returning all vapors generated during loading to the NGL storage tanks. In the event of a malfunction in the vapor return system, all vapors shall be sent to the emergency flare where they will be combusted before release to the atmosphere. Such malfunctions shall be reported to the APCD as a breakdown pursuant to APCD Rule 505 or variance relief shall be obtained.

(b) *NGL Flowline* – POPCO shall transport NGLs from its gas plant to Exxon's Stripping Gas Treating plant via the NGL flowline in accordance with the requirements of Condition P-14 of the Santa Barbara County Final Development Plan 93-DP-015. A monthly summary of the total volume (e.g., gallons) of NGL transferred from POPCO to the ExxonMobil facility shall be recorded and reported to the APCD.

(c) *NGL Storage Tanks* – POPCO shall remove from NGL service two of the five NGL storage tanks. These units shall be locked out of service in a manner that is satisfactory to the Air Pollution Control Officer. POPCO shall provide the APCD, in writing, with the following information on the out of service tanks: a) the tank numbers; b) the contents (e.g., hydrocarbon, water, nitrogen) within each; and c) the method(s) by which each is prevented from being placed back into service. [*Re: ATC 9047, ATC 9675*]

C.27 **PDS/TDS/SDS/Pig Receiver Eductor Vapor Recovery System.** The PDS/TDS/SDS eductor system shall be equipped with a high-pressure alarm set to alarm at 5.5 psig. Any high-pressure alarm indicated by this sensor shall be recorded by the plant Distributed Control System ("DCS"), and be reported to the APCD.

(a) Lean-Sulfinol shall continually flow through eductor J-203 at all times when POPCO is processing sour gas and the PDS is operational. This shall be evidenced by the upstream and downstream lean-Sulfinol valves being configured to the open positions during the conditions described above

(b) Maintenance logs of the eductor and pressure controller systems shall be kept on site by the permittee and made available for APCD inspection upon request. This permit requires no other recordkeeping, if the Operational Limitations of this permit are adhered to by the permittee at all times. [*Re: ATC/PTO 9471, ATC 9471-1*]

C.28 **Fuel Gas Sampling**. POPCO shall provide means of sampling the fuel gas to any combustion equipment that vents to the atmosphere. Such sample access shall be compatible with a Draeger or Kitigawa-type gas detector, or other APCD approved sampling method. [*Re: PTO 8092*]

C.29 **Cold Facility Startup and Shutdown**. The APCD shall be provided reasonable advance notification of a cold facility startup following a planned facility shutdown. Such notification shall provide sufficient time to allow the APCD opportunity to schedule APCD staff or their designee to witness the startup activities. [*Re: PTO 8092*]

(a) POPCO shall submit a letter to the APCD twenty-four (24) hours prior to any scheduled complete depressurization of the plant. The letter shall identify the purpose of the shutdown, the units to be shutdown, and the anticipated period the unit will be inoperable. At the conclusion of the shutdown, POPCO shall submit a letter to the APCD identifying the startup date, no later than one week after startup.

C.30 **Mass Emission Limitations**. Except as noted in Conditions 9.C.2 and 9.C.3, mass emissions for each equipment item (i.e., emissions unit) associated with the POPCO Gas Plant shall not exceed the limits listed in Tables 5.3 and 5.4. Emissions from the entire facility shall not exceed the total limits listed in Table 5.5. In addition, POPCO shall not exceed the device capacity specification values for each emission unit as listed in Table 5.1. Compliance with, and enforcement of the device-specific emission limits, and capacities listed in this permit shall be determined through the monitoring, reporting and recordkeeping requirements of this permit. [*Re: ATC 9047, PTO 8092, ATC/PTO 9471, ATC 9471-1, ATC 9487, ATC 9675*]

C.31 **Permitted Equipment.** Only those equipment items listed in Attachment 10.4 are covered by the requirements of this permit and APCD Rule 201.E. [*Re: ATC 9047*]

C.32 **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, POPCO 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: ATC 9047-4*]

C.33 **As-Built Drawings.** POPCO shall maintain current "as-built" drawings (P&IDs and PFDs) for the POPCO facility and make them available for inspection upon request. [*Re: ATC 9047*]

C.34 **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 the Project and shall be made available to APCD inspection staff upon request.

(a) *1983 Flaring Analysis* (as revised July 1984)

(b) *Vacuum Truck Plan* (ExxonMobil Plan approved 6/14/1993)

(c) *CEM Plan* (to be submitted to the APCD for approval within 60 days of the date this permit is issued)

(d) *The Odor Monitoring Plan* (approved 9/1993)

(e) *Rule 359 Flare Minimization Plan* (limited approval on 1/5/1996)

(f) *POPCO I&M Manual for Control of Reactive Organic Compound Emissions* (submitted 9/1998)

(g) *Process Monitor and Calibration Maintenance Plan* (approved 11/13/2001)

(h) *Fuel Gas Sulfur and HHV Reporting Plan* (conditionally approved 10/29/1998)

(i) *Diesel IC Engine Particulate Matter Operation and Maintenance Plan* (approved 3/13/1998)

(j) *SRU Failure Mitigation System Test Plan* (approved 3/13/1998)

(k) *POPCO's Breakdown Procedures Manual*

(l) *Emergency Episode Plan* (approved 1/17/2003)

(m) *Solvent Reclamation Plan* (conditionally approved 3/13/2000)

(n) *Thermal Oxidizer Combustor Maintenance Plan* (approved 9/5/2000)

(o) *Steam Injection Operating and Monitoring Plan* (approved 9/8/2004)

(p) *Rule 331 Fugitive Hydrocarbon Inspection and Maintenance Plan* (approved 8/7/2000)

(q) *Shutdown and Depressurization Plan* (approved 3/9/2001)

(r) *PSD Air Quality Monitoring Plan* (approved 3/1993)[*Re: ATC 9047, ATC 9047-4]*

C.35 **Visible Emissions – Rule 302**

(a) Planned and Unplanned Flaring (Thermal Oxidizer*)*: No visible emissions shall occur from any planned or unplanned flaring events. POPCO shall perform a visible emissions observation for a one-minute period once per quarter during a planned intermittent flaring event occurring during daylight hours. If a daylight planned-intermittent flaring event does not occur during the calendar quarter, no monitoring is required. For each unplanned flaring event during daylight hours that is greater than six-minutes in duration, a visible emissions observation for a one-minute period shall be performed. The observation shall begin no later than six-minutes after the time the unplanned flaring event begins, and if the total flare event is less than 7 minutes, the observation may be less than the full one minute. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.

(b) Boilers (B-801A & B-801B): No visible emissions shall occur from Boiler B-801A or B-801B. Once per calendar quarter, ExxonMobil shall perform a visible emissions inspection for a one-minute period from each boiler. The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.

(c) Diesel Fueled IC Engines: No visible emissions shall occur from any diesel fueled engines. Once per calendar quarter, POPCO shall perform a visible emissions inspection for a one-minute period on each diesel engine when operating, except for diesel engine powered vehicles on-site and diesel engines that qualify as non-road engines per the definition in 40 CFR 89.2. For the firewater pump, POPCO shall perform a one-minute visible emission inspection each time the firewater pump is operated longer than 15 minutes during any testing or emergency drills (otherwise no inspection is required). The start-time and end-time of each visible emissions inspection shall be recorded in a log, along with a notation identifying whether visible emissions were detected. All records shall be maintained consistent with the recordkeeping condition of this permit.

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.

D.1 **Tanks.** The following equipment is included in this emissions category:

Device Type	Device Subtype	APCD DeviceNo
Storage Tanks		
Methanol Tank (T-111)		102620
Wastewater Tank (T-601)		103103
Wastewater Tank (T-807)		103104

(a) Emission Limits: Mass emissions from the storage tanks listed in the Device Type table above shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance with this condition shall be based on the monitoring, recordkeeping and reporting conditions in this permit. Emissions from the storage tanks shall be determined using the emission factors in Table 5.2. Emissions from the methanol tank shall also be determined using actual throughput data.

D.2 **Diesel Internal Combustion Engines**. The following equipment is included in this emissions category:

Device Type	POPCO ID	APCD DeviceNo
Diesel Internal Combustion Engines		
Firewater Pump	P-805	2359
Firewater Pump	P-806	2356
Emergency Generator	G-800	2358
Emergency Air Generator	K-802	105147

(a) Emission Limitations. The mass emissions from the emergency generators (DeviceNo 2358 and 105147) shall not exceed the values listed in Table 5.3 and 5.4. Compliance shall be based on the operational, monitoring, recordkeeping and reporting conditions of this permit

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

(i) *Maintenance & Testing Use Limit* - The stationary emergency standby diesel-fueled CI engine(s) subject to this permit, except for in-use firewater pump engines, shall limit maintenance and testing[q] operations to no more than the hours listed in Table 5.1.

(ii) *Impending Rotating Outage Use* - The stationary emergency standby diesel-fueled CI engine(s) subject to this permit may be operated in response to the notification of an impending rotating outage if all the conditions cited in Section (e)(2)(A)(2) or Section (e)(2)(B)(1) of the ATCM are met, as applicable.

(iii) *Fuel and Fuel Additive Requirements* - The permittee may only add fuel and/or fuel additives to the engine or any fuel tank directly attached to the engine that comply with Section (e)(1)(A) or Section (e)(1)(B) of the ATCM, as applicable. This provision may be delayed pursuant to the provisions of Section (c)(19) of the ATCM.

(iv) *Firewater Pumps* - The stationary emergency standby diesel-fueled CI engine(s) (DeviceNo 2356 and 2359) are operated as firewater pumps shall not operate more than the number of hours necessary to comply with the testing requirements of the current National Fire Protection Association (NFPA) 25 – "*Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems*".

(v) *Temporary Engine Replacements* - *DICE ATCM* - Any reciprocating internal combustion engine subject to this permit and the stationary diesel ATCM may be replaced temporarily only if the requirements (1 – 7) listed herein are satisfied.

(1) The permitted engine is in need of routine repair or maintenance.

(2) The permitted engine that is undergoing routine repair or maintenance is returned to its original service within 180 days of installation of the temporary engine.

(3) The temporary replacement engine has the same or lower manufacturer rated horsepower and same or lower potential to emit of each pollutant as the permitted engine that is being temporarily replaced. At the written request of the permittee, the APCD may approve a replacement engine with a larger rated horsepower than the permitted engine if the proposed temporary engine has manufacturer guaranteed emissions (for a brand new engine) or source test data (for a previously used engine) less than or equal to the permitted engine.

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[p] As used in the permit, "ATCM" means Section 93115, Title 17, California Code of Regulations. Airborne Toxic Control Measure for Stationary Compression Ignition (CI) Engines
[q] "maintenance and testing" is defined in Section (d)(41) of the ATCM

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

(5) For each permitted engine to be temporarily replaced, the permittee shall submit a completed *Temporary IC Engine Replacement Notification* form (Form ENF-94) within 14 days of the temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

(6) Within 14 days upon return of the original permitted engine to service, the permittee shall submit a completed *Temporary IC Engine Replacement Report* form (Form ENF-95). This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

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

(vi) *Permanent Engine Replacements* - Any E/S engine, firewater pump engine or engine used for an essential public service that breaks down and can not be repaired may install a new replacement engine without first obtaining an ATC permit only if the requirements (1 – 6) listed herein are satisfied.

(1) The permitted stationary diesel IC engine is an E/S engine, a firewater pump engine or an engine used for an essential public service (as defined by the APCD).

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

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

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

(5) For each permitted engine to be permanently replaced pursuant to the condition, the permittee shall submit a completed *Permanent IC Engine Replacement Notification* form (Form ENF-96) within 14 days of either the permanent or temporary engine being installed. This form shall be sent electronically to: *temp-engine@sbcapcd.org*.

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

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

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

(ix) *Enrollment in a DRP/ISC - January 1, 2005* - Any stationary diesel IC engine rated over 50 bhp that enrolls for the first time in a Demand Response Program/Interruptible Service Contract (as defined in the ATCM) on or after January 1, 2005, shall first obtain an APCD Authority to Construct permit to ensure compliance with the emission control requirements and hour limitations governing ISC engines.

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

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

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

(i) emergency use hours of operation;

(ii) maintenance and testing hours of operation;

(iii) hours of operation for emission testing to show compliance with Section (e)(2)(A)(3) or Section (e)(2)(B)(3) {if specifically allowed for under this permit}

(iv) hours of operation for all uses other than those specified in items (a) – (c) above along with a description of what those hours were for.

(v) The owner or operator shall document fuel use through the retention of fuel purchase records that account for all fuel used in the engine and all fuel purchased for use in the engine, and, at a minimum, contain the following information for each individual fuel purchase transaction:

(1) identification of the fuel purchased as either CARB Diesel, or an alternative diesel fuel that meets the requirements of the Verification Procedure, or an alternative fuel, or CARB Diesel fuel used with additives that meet the requirements of the Verification Procedure, or any combination of the above;
(2) amount of fuel purchased;
(3) date when the fuel was purchased;
(4) signature of owner or operator or representative of owner or operator who received the fuel;
(5) signature of fuel provider indicating fuel was delivered.

(vi) hours of operation to comply with the requirements of the NFPA for healthcare facilities or firewater pumps (for DeviceNo 2356 and 2359)

(e) Reporting**.** By March 1 of each year, a written report documenting compliance with the terms and conditions of this permit and the ATCM for the previous calendar year shall be provided by the permittee to the APCD (Attn: *Annual Report Coordinator*). All logs and other basic source data not included in the report shall be made available to the APCD upon request. The report shall include the information required in the Recordkeeping Condition above and may be submitted with the CVR required per Condition C.10 of this permit.

D.3 **External Combustion.** The following equipment is included in this emissions unit category:

Device Type	POPCO ID	APCD DeviceNo
External Combustion Equipment		
Sulfinol TEG Reboiler	E-251	2352

(a) Emissions Limits: The mass emissions from Sulfinol TEG Reboiler E-251 shall not exceed the limits listed in Tables 5.3 and 5.4. Compliance shall be based on the monitoring, recordkeeping, and reporting conditions of this permit.

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

(i) *Sulfinol TEG Reboiler Heat Input Limit* - The hourly, daily and annual heat input limits to device number 2352 shall not exceed the values listed in Table 5.1. These limits are based on the design rating of the unit and the annual heat input value as listed in the permit application.

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

On or before January 30, 2019, the owner or operator of any existing unit shall:

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

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

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

(c) Monitoring: The volume of natural gas (in units of standard cubic feet) used by Sulfinol TEG Reboiler E-251 shall be reported as permitted annual heat input limit for the unit (Btu/year) divided by the APCD-approved heating value of the fuel (Btu/scf).

(d) Recordkeeping: A logbook or electronic file shall be kept that documents all maintenance and calibration performed for the Sulfinol TEG Reboiler.

(e) Reporting**.** By March 1 of each year, a written report documenting compliance with the terms and conditions of this permit and the ATCM for the previous calendar year shall be provided by the permittee to the APCD (Attn: *Annual Report Coordinator*). All logs and other basic source data not included in the report shall be made available to the APCD upon request. The report shall include the volume of natural gas used and the information required in the Recordkeeping Condition above and may be submitted with the CVR required per Condition C.10 of this permit.

AIR POLLUTION CONTROL OFFICER

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Date

Attachments:

1 - Emission Calculation Documentation
2 - Source NEI
3 - Equipment List
4 – APCD Response to Comments
5 - Fee Statement

Notes:

Reevaluation Due Date: June 2012
Semi-Annual reports are due by March 1st and September 1st of each year

10.0 Attachments

10.1. Emissions Calculation Documentation

This attachment contains emission calculation spreadsheets and other supporting calculations used for the emission tables in Section 5 and permit conditions in Section 9. Refer to Section 4 for the general equations, assumptions and emission factor basis used.

Table 10.1 Calculations for Estimated Exempt Emissions

A. Exempt IC Engine Calcs

Description	APCD ID#	Exemption Claimed	bhp	hrs/yr	NOx	ROC	CO	SOx	PM	PM10
		Device Specifications			Tons Per Year (TPY)[a]					
Crane (200 ton) Hydraulic		202.D.5	200.0	25.7	0.08	0.01	0.02	0.01	0.01	0.01
CAT 416 C Backhoe		202.F.1.c	75.0	59.6	0.07	0.00	0.01	0.01	0.00	0.00
Crane (25 ton)		202.F.1.c	210.0	8.8	0.03	0.00	0.01	0.00	0.00	0.00
Crane (300 ton) #103958		202.F.1.c	360.0	13	0.07	0.00	0.02	0.01	0.01	0.01
Crane (35 ton)		202.F.1.c	205.0	12.5	0.04	0.00	0.01	0.00	0.00	0.00
Crane (75 ton) #102006		202.F.1.c	190.0	87.2	0.26	0.02	0.06	0.03	0.02	0.02
Crane (8 ton)		202.F.1.c	76.0	8.4	0.01	0.00	0.00	0.00	0.00	0.00
Manlift - 60 ft		202.F.1.c	50.0	30	0.02	0.00	0.01	0.00	0.00	0.00
Manlift - 65 ft		202.F.1.c	56.0	27	0.02	0.00	0.01	0.00	0.00	0.00
#1 Light Tower		202.F.1.e	10.7	54	0.01	0.00	0.00	0.00	0.00	0.00
#2 Light Tower		202.F.1.e	10.7	54	0.01	0.00	0.00	0.00	0.00	0.00
#3 Light Tower		202.F.1.e	10.7	54	0.01	0.00	0.00	0.00	0.00	0.00
#4 Light Tower		202.F.1.e	10.7	54	0.01	0.00	0.00	0.00	0.00	0.00
Welder - Lincoln Portable		202.F.1.e	38.2	27	0.02	0.00	0.00	0.00	0.00	0.00
Welder - Lincoln Portable		202.F.1.e	38.2	8.5	0.01	0.00	0.00	0.00	0.00	0.00
Air Compressor		202.F.2	460.0	37	0.26	0.02	0.06	0.03	0.02	0.02
Dust Collector		202.F.2	18.0	30.9	0.01	0.00	0.00	0.00	0.00	0.00
Dust Collector		202.F.2	25.0	41	0.02	0.00	0.00	0.00	0.00	0.00
WaterBlaster (HydroPress)		202.F.2	174.0	18.9	0.05	0.00	0.01	0.01	0.00	0.00
Pump - N2 #101589			478.0	3	0.02	0.00	0.00	0.00	0.00	0.00
Sum of engines with 20 < bhp < 100			**641.1**							

B. Exempt External Combustion Calcs

Description	APCD ID#	Exemption Claimed	MMBtu/hr	hrs/yr	NOx	ROC	CO	SOx	PM	PM10
		Device Specifications			Tons Per Year (TPY)[b]					
TEG Reboiler E-121	2353	202.G.1	1.200	8760	0.52	0.03	0.43	0.07	0.04	0.04
TEG Reboiler E-251	2352	202.G.1	2.100	8760	0.90	0.05	0.76	0.12	0.07	0.07
Forced Air Furnace	8792	202.G.1	0.050	8760	0.02	0.00	0.02	0.00	0.00	0.00

C. Other Exemption Calcs

Description	APCD ID#	Exemption Claimed	hrs/yr	NOx	ROC	CO	SOx	PM	PM10
		Device Specifications		Tons Per Year (TPY)					
Surface Coating-Maintenance		202.D.8		0.00	0.20	0.00	0.00	0.00	0.00
Abrasive Blasting		202.H.3		0.00	0.00	0.00	0.00	0.00	0.00

Notes:

[a]Annual Emissions calculated using emission factors from AP-42, Table 3.3-1

[b]Annual Emissions for external combustion equipment calculated using emission factors from AP-42, Table 1.4-1 and Table 1.4-2

10.2 Source NEI

Table 10.2 Stationary Source Net Emissions Increase

I. This Project's Facility NEI-90

Facility	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
3170		**6.98**	**0.85**	**16.32**	**3.08**	**132.77**	**23.37**	**70.22**	**12.95**	**1.32**	**0.10**	**1.26**	**0.10**

II. Other Facility "P1s" at this SSN
Enter all other facility "P1" NEI-90s below:

Facility	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
1482		1,008.93	98.58	866.40	70.01	551.55	87.64	249.31	44.26	289.19	47.73	237.26	38.48
8009		901.42	0.00	20.88	3.73	142.83	0.44	45.21	0.00	53.36	0.00	51.23	0.00
8018		447.28	0.00	24.63	2.87	70.71	0.29	-2.31	0.00	26.45	0.00	25.39	0.00
8019		450.58	0.00	35.70	4.83	71.42	0.29	22.60	0.00	26.69	0.00	25.61	0.00
Totals		**2,808.21**	**98.58**	**947.60**	**81.44**	**836.51**	**88.66**	**314.81**	**44.26**	**395.69**	**47.73**	**339.49**	**38.48**

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

III. Other Facility "P2" NEI-90 Decreases at this SSN
Enter all other facility "P2" NEI-90s below:

Facility	Date	NOx		ROC		CO		SOx		PM		PM10	
No.	Issued	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
1482		0.00	1.04	15.04	2.74	0.00	0.25	0.00	0.13	0.00	0.13	0.00	0.12
Totals		**0.00**	**1.04**	**15.04**	**2.74**	**0.00**	**0.25**	**0.00**	**0.13**	**0.00**	**0.13**	**0.00**	**0.12**

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

IV. Other Facility Pre-90 "D" Decreases at this SSN
Enter all other facility "D" decreases below:

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

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

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

	NOx		ROC		CO		SOx		PM		PM10	
Term	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr	lb/day	ton/yr
Project Facility "I"	6.98	0.85	16.32	3.08	132.77	23.37	70.22	12.95	1.32	0.10	1.26	0.10
Other Fac P1	2,808.21	98.58	947.60	81.44	836.51	88.66	314.81	44.26	395.69	47.73	339.49	38.48
Other Fac P2	0.00	1.04	15.04	2.74	0.00	0.25	0.00	0.13	0.00	0.13	0.00	0.12
Other Fac D	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
SSN NEI-90	**2,815.19**	**98.39**	**948.88**	**81.77**	**969.28**	**111.77**	**385.03**	**57.08**	**397.01**	**47.70**	**340.75**	**38.45**

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

10.3 Equipment List (Exempt/Insignificant Equipment)

The list below designates APCD Rule 202 permit exempt list of emissions units at POPCO Gas Plant. This list also serves to designate those emission units as insignificant under Part 70.

1. E-121, TEG Reboiler rated at 1.2 MMBtu/hr and fired exclusively on PUC quality natural gas.

2. Forced Air Furnace rated at 50,000 Btu/hr and fired exclusively on PUC quality natural gas.

3. Portable Abrasive blasting equipment (does not include associated IC engine).

4. 5-Gallon batch tank and associated metering pump.

5. Single pieces of degreasing equipment that have a liquid surface area of less than one square foot and where the total aggregate liquid surface area of all such units at the stationary source is less than 10 square feet.

6. Diesel fuel storage tanks.

7. Lube oil storage tanks.

8. Refrigerant make-up tank (T-151), propane 10,000-gallon capacity

10.4 APCD Response to Comments

The APCD received the following comments on the draft permit:

Equipment Affected:	Section	Issue	Proposed Resolution	APCD Response
Boiler A & B CEMS Changes	3.4.2	**Rule 342 –** APCD added discussion regarding changes to CEMS requirements for the boilers – Discussion does not make reference NOx, which is the pollutant whose CEMs requirement is being changed	Second line add NOx before limits, Fourth line add NOx before concentration, Fifth line add NOx before compliance.	Done
	Table 4.10	• CEMS concentration parameter is incorrectly identified. • The sliding hourly average should be removed from the NOx ppm parameter	• Change "ANOXPPMC" to "ANOXPPM3" and "BNOXPPMC" to "BNOXPPM3" • Averaging period should only be "6-minute" for NOx ppm on boilers A and B	ANOXPPMC is uncorrected concentration, this will continue to be monitored, but the 30 ppmv permit limit will be removed from the table, since it applies to the concentration corrected to 3% O_2. The averaging period was corrected.
	9.C.13 Table 9.1	NOx CEMS concentration parameter is incorrectly identified.	Change "ANOXPPMC" to "ANOXPPM3" and "BNOXPPMC" to "BNOXPPM3"	NO_x concentrations no longer need to be reported, since the CEMS is only used to determine compliance with mass emission limits. These two parameters have been removed from the table.
Sulfinol TEG Reboiler	5.3	The Sulfinol TEG Reboiler has not been added to the list of devices assumed for the reasonable worst case operating scenario	Include the Sulfinol TEG Reboiler in the list of devices	Done

Equipment Affected:	Section	Issue	Proposed Resolution	APCD Response
	9.C.1(a)	• TEG Reboiler APCD Device No. has been changed • The APCD incorrectly identified the TEG Reboiler ID number in PTO 12680	• There have been no changes to the TEG Reboiler, other than a loss of a Rule 202 exemption, please change the APCD Device No. back to 2352 and delete 111759 • See condition 9.C.1 in the current PTO 8092 R6 and Table 10.1 for the correct APCD ID#, ExxonMobil ID#, and device rating (MMBtu/hr) - Change E-121 to E-251	The sulfinol Reboiler E-251 is APCD Device No. 2352. It is rated 2.1 MMBtu/hr and is now subject to permit. TEG Reboiler E-121 is APCD Device No. 2353. It is rated 1.2 MMBtu/hr and permit exempt. APCD device No 111759, which was a duplicate device ID for E-121 has been deleted.
	9.C.1(b)(v) and (vii), and (c)(iii)	Permit conditions related to the TEG boiler come from APCD PTO 12680 which is not federally enforceable.	Insert a condition in section 9.D which incorporates the conditions found in PTO 12680 for the TEG Reboiler and remove the TEG reboiler conditions from 9.C.1.	Done; emissions tables have also been updated to remove TEG Reboiler emissions from federal PTE.
	9.C.1(c)(iii)	TEG Reboiler ID is incorrect	Change E-121 to E-251	Done
Source Test Plans	9.C.18(b)	The source testing condition requires that POPCO submits a source test plan for approval prior to initiating a source test. Unless there have been modifications to equipment requiring a revised plan, is POPCO required to provide a new plan every time?	Request that this condition be revised to specify that for new equipment, or modifications to existing equipment, that a source test plan be submitted to the APCD for approval at least 30 days prior to initiating a source test. Otherwise, existing equipment may be tested based on the previously approved source test plan.	This condition will be unchanged. ExxonMobil may refer to previous source test plans, but must submit a new plan for each source test if one is requested by the APCD.

Equipment Affected:	Section	Issue	Proposed Resolution	APCD Response
Diesel ICE	3.3	The section, Compliance with State Rules and Regulations does not include a discussion regarding the applicability of the stationary diesel ATCM	Create a new subsection, 3.3.3 which discusses the applicability of the stationary diesel ATCM, similar to the section found in LFC's permit.	Done
Thermal Oxidizer	Table 5.1 – 5.4	Missing the new Unplanned Other – Miscellaneous category defined in ATC/PTO 12020	Please incorporate this new category, and adjust existing categories per AP 12020	Done
	9.C.10 (b) (5) and (6)	These conditions require a copy of the Flare Event Log and the Infrequent Flaring Events Log for the reporting period. The Flare Event Log includes all flare events, including infrequent events, and maintains a count of the number of events of each type. As such, the Infrequent Flaring Events Log seems redundant.	Condition (vi) was removed, but not merged in with (v). Request that the two conditions be merged into one, similar to the revised condition for LFC.	Done
HAP Emissions	Table 5.7	The weight fractions applied to some of the equipment at the facility appears to be incorrect or inconsistent. (a) **Fugitive Hydrocarbons – Gas Service** – CARB speciation profile #757 – Gas Service does not identify any PAH's. The weight fraction applied to the emission factor in the PAH column is actually the weight fraction for hexane. (b) **Solvent Usage** – The solvents used by POPCO are assumed to consist of 100% xylene, while the solvents used by LFC are assumed to be 2% benzene, 2% xylene, and 2% toluene.	(a) **Fugitive Hydrocarbons – Gas Service** –Please shift the data in the PAH column to the hexane heading. (b) **Solvent Usage** – POPCO and LFC use the same type of solvents for cleaning, please adjust the HAP emission calculations so that the same HAP weight fractions are assumed at both facilities.	(a) Already done (b) Done, 5% each by weight for benzene, xylene, and toluene will be assumed, consistent with other APCD permits.

Equipment Affected:	**Section**	**Issue**	**Proposed Resolution**	**APCD Response**
Wastewater Tanks	9.C.5(b)(iv)	Source Testing frequency conflicts with reference added in Table 4-15	Change Table 4-15 frequency to every two years	Done
Rule 202 Exemptions	3.1	• Rule 202 exempt equipment is listed in a table as well as in bullet format. There is some duplication • The APCD Device No. for the TEG Reboiler (E-251) was changed – Also this device should not be listed as it is no longer exempt • There are more than one permit exempt diesel storage tank	• Suggest that the 202 equipment either be listed in a table or in bullet format but not both – is somewhat confusing. • Remove E-251 from the list of Rule 202 exempt devices • Revise the Equipment Description for the Diesel Storage Tank to refer to "Diesel Storage Tanks"	Done
	3.4.2	Rule 311 – Discussion does not reference the use of CARB diesel	Add a discussion regarding the use of CARB diesel like the OCS permits	Done
Small Boilers	9.B	Should there be a condition pertaining to Rule 361?	Add condition pertaining to new boiler rule, Rule 361.	Rule 361 requirements are contained in section 9.C and 9.D.
	9.D.2(b)(i) and D.3(b)(i)	There is no Table 5.1-1	Change to 5.1	Done
Exempt Emissions	Table 5.9	The Sulfinol TEG Reboiler is listed in the exempt emissions table	Please remove this device as it is no longer exempt.	Done.

FEE STATEMENT
PT-70/Reeval No. 08092 - R7
FID: 03170 POPCO / SSID: 01482

Device Fee

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
002358	Emergency Generator (G-800)	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
102618	Fugitive HC Components - CLP - Gas/Cond Svc	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105163	Acid Gas KO Drum	A6	3.010	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105165	Sour Water Pumps	A2	1.500	30.41	Per total rated hp	Min	2	1.000	116.56	0.00	0.00	116.56
105166	Ammonia Injection System	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105167	SRU Reaction Furnace	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105168	Reaction Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105169	Sulfur Condenser No. 1	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105170	Reheat Burner No. 1	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105171	Converters	A6	8.890	3.36	Per 1000 gallons	Min	3	1.000	174.84	0.00	0.00	174.84
105172	Sulfur Condenser No. 2	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105173	Reheat Burner No. 2	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105175	Reheat Burner No. 3	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105177	Steam Condenser	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105178	Sulfur Pit	A6	59.520	3.36	Per 1000 gallons	No	1	1.000	199.99	0.00	0.00	199.99
105179	Sulfur Charge Pump	A2	20.000	30.41	Per total rated hp	No	1	1.000	608.20	0.00	0.00	608.20
105180	Sulfur Pit Vent Blower	A2	3.000	30.41	Per total rated hp	No	2	1.000	182.46	0.00	0.00	182.46
105181	Sulfur Degassing Pumps	A2	20.000	30.41	Per total rated hp	No	3	1.000	1,824.60	0.00	0.00	1,824.60
105182	Sulfur Loading Pumps	A2	5.000	30.41	Per total rated hp	No	2	1.000	304.10	0.00	0.00	304.10
105184	Reducing Gas Generator	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105185	Venturi Contactor	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105186	Venturi Contactor No. 1	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105187	Spray Tower	A6	2.250	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105147	Reaction Tank	A6	24.720	3.36	Per 1000 gallons	No	1	1.000	83.06	0.00	0.00	83.06

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105188	Solution Circulation Pumps	A2	150.000	30.41	Per total rated hp	No	2	1.000	9,123.00	0.00	0.00	9,123.00
105189	Venturi Contactor No. 2	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105190	Absorber Tower	A6	20.620	3.36	Per 1000 gallons	No	1	1.000	69.28	0.00	0.00	69.28
105191	Oxidizer Tank No. 1	A6	46.060	3.36	Per 1000 gallons	No	1	1.000	154.76	0.00	0.00	154.76
105192	Oxidizer Tank No. 2	A6	0.840	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105193	Citric Acid Tank	A6	0.210	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105210	Rinse Water Receiver	A6	0.020	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105198	Balance Tank	A6	2.580	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105199	Evaporative Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105200	Solution Heater	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105201	Evaporative Cooler Pump	A2	20.000	30.41	Per total rated hp	No	1	1.000	608.20	0.00	0.00	608.20
105202	Solution Circulation Pumps	A2	150.000	30.41	Per total rated hp	No	2	1.000	9,123.00	0.00	0.00	9,123.00
105203	Stretford Sewer Pit Pump	A2	2.000	30.41	Per total rated hp	No	1	1.000	60.82	0.00	0.00	60.82
105205	Make-Up Pump	A2	2.000	30.41	Per total rated hp	No	1	1.000	60.82	0.00	0.00	60.82
105206	Chemical Make-Up Pit	A6	0.010	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105207	Sulfur Slurry Tank	A6	10.580	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105208	Sulfur Melter/Storage Tank	A6	3.010	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105209	Sulfur Meter Pump	A2	5.000	30.41	Per total rated hp	No	1	1.000	152.05	0.00	0.00	152.05
102620	Methanol Tank	A6	14.610	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105221	Feed Gas Water Separator	A6	1.600	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56
105222	TEG Contactor	A6	4.321	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105224	Gas/Gas Exchanger	A1.a	1.000	58.66	Per equipment	No	4	1.000	234.64	0.00	0.00	234.64
105225	Gas/Stabilizer Feed Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105226	Gas Chillers	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105227	Main Separators	A6	6.350	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105228	Water Separator	A6	7.245	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105229	Flare Knockout Pot	A6	0.010	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105230	Bypass Separator	A6	9.386	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105232	Stabilizer Feed/Bottoms Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105233	Stabilizer	A6	10.290	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105234	Stabilizer Reboiler	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105235	Stabilizer Overhead Condenser	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105236	Stabilizer Reflux Accumulator	A6	1.676	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105237	Stabilizer Pumps	A2	7.500	30.41	Per total rated hp	No	2	1.000	456.15	0.00	0.00	456.15
105267	NGL Storage Tank #1	A6	83.730	3.36	Per 1000 gallons	No	1	1.000	281.33	0.00	0.00	281.33
105268	NGL Storage Tank #2	A6	83.730	3.36	Per 1000 gallons	No	1	1.000	281.33	0.00	0.00	281.33
105269	NGL Storage Tank #3	A6	83.730	3.36	Per 1000 gallons	No	1	1.000	281.33	0.00	0.00	281.33
105270	NGL Storage Tank #4	A6	83.730	3.36	Per 1000 gallons	No	1	1.000	281.33	0.00	0.00	281.33
105271	NGL Storage Tank #5	A6	83.730	3.36	Per 1000 gallons	No	1	1.000	281.33	0.00	0.00	281.33
105272	NGL Product Pumps	A2	20.000	30.41	Per total rated hp	No	2	1.000	1,216.40	0.00	0.00	1,216.40
105273	Methanol Injection Pumps	A2	25.000	30.41	Per total rated hp	No	2	1.000	1,520.50	0.00	0.00	1,520.50
105274	NGL Booster Pump	A2	25.000	30.41	Per total rated hp	No	1	1.000	760.25	0.00	0.00	760.25
105275	NGL Transfer Pump	A2	50.000	30.41	Per total rated hp	No	1	1.000	1,520.50	0.00	0.00	1,520.50
104831	GPU TEG Flash Drum	A6	0.370	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105211	Rich TEG Particulate Filter	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105212	Rich TEG Carbon Filter	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105213	Lean TEG Feed Pumps	A2	3.000	30.41	Per total rated hp	No	3	1.000	273.69	0.00	0.00	273.69
105214	TEG Stripping Column	A6	0.060	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105215	Lean/Rich TEG Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105216	Stripper Reflux Accumulator	A6	0.040	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105217	Stripper Overhead Condenser	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105218	Lean TEG Surge/Storage Drum	A6	1.150	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105219	Sample Return Pot	A6	0.004	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105220	TEG Stripper Reflux Pumps	A2	3.000	30.41	Per total rated hp	No	2	1.000	182.46	0.00	0.00	182.46
105223	TEG/Gas Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105231	Flash/Gas Refrigerant Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105258	Refrigerant Make-Up Pump	A2	20.000	30.41	Per total rated hp	No	1	1.000	608.20	0.00	0.00	608.20
105259	Refrigerant Surge Tank	A6	13.900	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105260	Refrigerant Flash Tank	A6	1.200	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105261	1st Stage Refrigerant Scrubber	A6	1.800	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105262	2nd Stage Refrigerant Scrubber	A6	1.800	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105263	1st Stage Suction Pulsation Bottle	A6	0.190	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56
105264	2nd Stage Suction Pulsation Bottle	A6	0.190	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56
105265	Refrigerant Compressor	A2	900.000	30.41	Per total rated hp	Max	2	1.000	11,776.68	0.00	0.00	11,776.68
105266	Refrigerant Condenser	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
104830	GPU TEG Flash Gas KO Pot	A6	0.013	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
104832	Fuel Gas Contactor	A6	0.549	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
104833	Low Pressure Flash Tank	A6	4.413	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
104834	Sour Gas Eductor	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105276	Treated Gas Wash Column	A6	3.950	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105277	Knockout Drum	A6	4.390	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105278	High Pressure Contactor	A6	16.460	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105279	Wash Column Pumps	A2	10.000	30.41	Per total rated hp	No	2	1.000	608.20	0.00	0.00	608.20
105280	Low Pressure Contactor	A6	14.290	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105281	Low Pressure Scrubber	A6	0.320	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105282	PDS/TDS/SDS Sour Gas Eductor	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105283	Treated Fuel Gas Scrubber	A6	0.030	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105284	Antifoam Injection Tank	A6	0.005	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105285	Lean Solvent Pumps	A2	250.000	30.41	Per total rated hp	Max	3	1.000	17,665.02	0.00	0.00	17,665.02
105286	Lean Solver Cooler	A1.a	1.000	58.66	Per equipment	No	4	1.000	234.64	0.00	0.00	234.64
105287	Lean/Rich Solvent Exchanger	A1.a	1.000	58.66	Per equipment	No	6	1.000	351.96	0.00	0.00	351.96
105300	Absorber	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105301	Sulfinol Carbon Filters	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105302	Lean Solvent Booster Pumps	A2	300.000	30.41	Per total rated hp	Max	3	1.000	17,665.02	0.00	0.00	17,665.02
105303	Sour Gas Eductor	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105304	Stripper	A6	31.900	3.36	Per 1000 gallons	No	1	1.000	107.18	0.00	0.00	107.18
105305	Stripper Reboiler	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105306	Stripper Overhead Condenser	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105307	Stripper Reflux Pumps	A2	5.000	30.41	Per total rated hp	No	2	1.000	304.10	0.00	0.00	304.10
105308	Stripper Reflux Accumulator	A6	0.620	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105339	Reflux Vaporizer	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105340	Reflux SuperHeater	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105341	Reclaimer	A5	0.254	73.33	Per sq ft of inside x-sec	Min	1	1.000	58.28	0.00	0.00	58.28
105342	Chemical Fill Pot	A6	0.004	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105343	Sulfinol Drain Vessel	A6	0.800	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105344	Solvent Drain Filter	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105345	Sulfinol Drain Pump	A2	10.000	30.41	Per total rated hp	No	1	1.000	304.10	0.00	0.00	304.10
105346	TEG Contactor	A6	4.320	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105348	TEG Disentrainment Separator	A6	0.070	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105451	1st Stage Suction Pulsation Bottle	A6	0.130	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105456	1st Stage Discharge Pulsation Bottle	A6	0.100	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105459	2nd Stage Discharge Pulsation Bottle	A6	0.070	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105460	Recompressor Intercooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105461	2nd Stage Suction Disentrainment Separator	A6	0.060	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105462	Recompressor A	A2	600.000	30.41	Per total rated hp	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105463	1st Stage Suction Pulsation Bottle B	A6	0.130	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105464	1st Stage Discharge Pulsation Bottle B	A6	0.100	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105465	Recompressor B	A2	600.000	30.41	Per total rated hp	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105466	2nd Stage Suction Pulsation Bottle B	A6	0.060	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105467	2nd Stage Discharge Pulsation Bottle B	A6	0.070	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105468	Recompressor Intercooler B	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105469	2nd Stage Suction Disentrainment Separator B	A6	0.040	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105470	2nd Stage Suction Pulsation Bottle	A6	0.080	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105471	Recompressor Gas Cooler	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
104836	Rich TEG Flash Drum	A6	1.500	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
104838	Stripper Overhead Condenser	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
104837	TEG Stripping Column	A6	0.120	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105347	TEG Gas Exchanger	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105349	Rich TEG Particulate Filter	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105350	Rich TEG Carbon Filter	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105351	High Pressure Particulate Filter	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105352	Lean TEG Feed Pumps	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105353	Lean TEG Feed Pump	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105354	Lean/Rich TEG Exchanger	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105355	Lean TEG Surge/Storage Drum	A6	2.810	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105448	Stripper Reflux Accumulator	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105449	TEG Stripper Reflux Pumps	A2	0.750	30.41	Per total rated hp	Min	2	1.000	116.56	0.00	0.00	116.56
105472	Knockout Drum	A6	2.870	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105478	Coalescing Filter	A6	0.130	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105479	Suction Pulsation Bottle A/B	A6	0.130	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
105480	Sales Gas Compressor A	A2	600.000	30.41	Per total rated hp	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105481	Suction Pulsation Bottle C/D	A6	0.130	3.36	Per 1000 gallons	Min	2	1.000	116.56	0.00	0.00	116.56
105482	Sales Gas Compressor B	A2	600.000	30.41	Per total rated hp	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105483	Sales Gas Cooler A	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105484	Sales Gas Coolers	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105485	Sales Gas Evaporative Cooler Water Pump	A2	3.000	30.41	Per total rated hp	No	1	1.000	91.23	0.00	0.00	91.23
105486	Discharge Pulsation Bottle A	A6	0.290	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105487	Discharge Pulsation Bottle B	A5	0.230	73.33	Per sq ft of inside x-sec	Min	1	1.000	58.28	0.00	0.00	58.28
105492	Steam Generator	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105525	Hydrogenation Reactor	A6	3.440	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105526	Reactor Effluent Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105527	Desuperheater/Contact Condenser	A6	5.450	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105528	Contact Condenser Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105529	Desuperheater Pump	A2	15.000	30.41	Per total rated hp	No	1	1.000	456.15	0.00	0.00	456.15
105530	Contact Condenser Pump & Common Spare	A2	10.000	30.41	Per total rated hp	No	2	1.000	608.20	0.00	0.00	608.20
105488	SWS Feed Surge Drum	A6	16.646	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105489	SWS Feed Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105490	SWS Feed Pumps	A2	5.000	30.41	Per total rated hp	No	2	1.000	304.10	0.00	0.00	304.10
105493	Sour Water Stripper	A6	0.637	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105494	SWS Bottoms Pumps	A2	3.000	30.41	Per total rated hp	No	2	1.000	182.46	0.00	0.00	182.46
105495	SWS Overhead Condenser	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105496	SWS Overhead Accumulator	A6	0.184	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105497	SWS Reflux Pumps	A2	0.500	30.41	Per total rated hp	Min	2	1.000	116.56	0.00	0.00	116.56
105498	SWS Bottoms Cooler	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
002351	Boiler B	A3	41.000	440.07	Per 1 million Btu input	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105500	Amine Injection Package	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66

Device No.	Device Name	Fee Schedule	Qty of Fee Units	Fee per Unit	Fee Units	Max or Min. Fee Apply?	Number of Same Devices	Pro Rate Factor	Device Fee	Penalty Fee?	Fee Credit	Total Fee per Device
002350	Boiler A	A3	41.000	440.07	Per 1 million Btu input	Max	1	1.000	5,888.34	0.00	0.00	5,888.34
105501	Chelant/Dispersant Injection Package	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105524	Boiler Off-Gas Knockout Drum	A6	1.820	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105508	Fuel Gas Knockout Drum	A6	0.290	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105503	Condensate Coolers	A1.a	1.000	58.66	Per equipment	No	2	1.000	117.32	0.00	0.00	117.32
105157	Flare KO Drum (Acid)	A6	1.460	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105158	Flare KO Drum (HC)	A6	2.180	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
002356	Firewater Pump (806)	A1.a	3.234	58.66	Per equipment	No	1	1.000	189.71	0.00	0.00	189.71
002359	Firewater Pump (805)	A1.a	3.234	58.66	Per equipment	No	1	1.000	189.71	0.00	0.00	189.71
105515	Storm Water/Oil Water Separator	A6	7.140	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105516	Stormwater Separator Pump	A2	1.500	30.41	Per total rated hp	Min	1	1.000	58.28	0.00	0.00	58.28
105506	Housekeeping Drain Vessel	A6	0.880	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105507	Housekeeping Drain Pump	A2	1.000	30.41	Per total rated hp	Min	1	1.000	58.28	0.00	0.00	58.28
002357	Emergency Air Generator	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
105510	Pressure Drain Vessel	A6	1.420	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105511	Pressure Drain Pump	A2	3.000	30.41	Per total rated hp	No	1	1.000	91.23	0.00	0.00	91.23
105513	TEG Drain Vessel	A6	0.880	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105514	TEG Drain Pump	A2	10.000	30.41	Per total rated hp	No	1	1.000	304.10	0.00	0.00	304.10
103103	Waste Liquid Storage Tank (601)	A6	91.800	3.36	Per 1000 gallons	No	1	1.000	308.45	0.00	0.00	308.45
103104	Waste Liquid Storage Tank (807)	A6	8.800	3.36	Per 1000 gallons	Min	1	1.000	58.28	0.00	0.00	58.28
105160	Waste Liquid Transfer Pump	A2	1.500	30.41	Per total rated hp	Min	1	1.000	58.28	0.00	0.00	58.28
106398	Gas Pig Receiver	A1.a	1.000	58.66	Per equipment	No	1	1.000	58.66	0.00	0.00	58.66
	Device Fee Sub-Totals =								**$128,211.07**	**$0.00**	**$0.00**	
	Device Fee Total =											**$128,211.07**

Permit Fee

Fee Based on Devices **128,211.07**

Fee Statement Grand Total = $128,211

Notes:

(1) Fee Schedule Items are listed in APCD Rule 210, Fee Schedule "A".
(2) The term "Units" refers to the unit of measure defined in the Fee Schedule.