ExxonMobil Chemical Company
5000 Bayway Drive
P.O. Box 4004
Baytown, Texas 77522-4004

ExxonMobil
Chemical

Certified Mail

January 22, 2016

Mr. Jeffrey Robinson
Air Permits Section (6PD-R)
U.S. EPA Region 6
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202

GHG Permit Rescission Request
Baytown Olefins Plant
Permit PSD-TX-102982-GHG
Ethylene Expansion Project

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AIR PERMITS SECTION

Dear Mr. Robinson:

On May 22, 2012, ExxonMobil Chemical Company (ExxonMobil) submitted to the Environmental Protection Agency (EPA) Region 6 a Prevention of Significant Deterioration (PSD) permit application for GHG emissions to construct a new ethylene production unit at the Baytown Olefins Plant (BOP), an existing major stationary source of criteria pollutants. The proposed project consists of eight steam cracking furnaces and recovery equipment, as well as associated utilities. ExxonMobil also submitted to the Texas Commission on Environmental Quality (TCEQ) a minor New Source Review (NSR) permit application for non-GHG pollutants in connection with the same proposed project. TCEQ issued the minor NSR Permit No. 102982 on February 18, 2014. EPA Region 6 issued Permit PSD-TX-102982-GHG on May 14, 2014, based on the applicability provisions described, at the time of permit issuance, at 40 CFR § 52.21(b)(49)(v)(b).[1]

According to 40 CFR § 52.21(w)(2)(iii), a permit holder may request that EPA rescind a permit if it was issued for a modification that was classified as a major modification solely on the basis of an increase in emissions of greenhouse gases. BOP currently operates under a Plant-wide Applicability Limit (PAL) permit PAL6 for non-GHG pollutants regulated under 40 CFR § 52.21. TCEQ's Construction Permit Source Analysis & Technical Review for the initial application for Permit No. 102982 (Project No 178224) stated that the emissions associated with the Ethylene Expansion Project "*...will be included in the established PAL limits with no increases to any of the established PAL limits, therefore, no federal applicability review for this project is required.*"[2] EPA issued the PSD permit for GHG in May 2014, recognizing that Permit No. 102928 is a minor NSR permit for non-GHG pollutants.[3] Therefore, ExxonMobil is hereby submitting this request for rescission of PSD Permit PSD-TX-102982-GHG, pursuant to 40 CFR § 52.21(w)(2)(iii).

[1] This provision has since been removed from 40 CFR in response to the court decisions in 2014 and 2015 (*U.S. Supreme Court decision in UARG v. EPA and D.C. Circuit amended judgment in Coalition for Responsible Regulation v. EPA*).
[2] See "Project Overview" on page 1 and NNSR/PSD review applicability discussion on page 3 of the *Construction Permit Data Analysis &Technical Review* in Attachment 1.
[3] See "Executive Summary" on page 1 of the *Statement of Basis* for Permit PSD-TX-102982-GHG in Attachment 3.

Supporting documents enclosed are:

- Attachment 1: a copy of the minor New Source Review (NSR) Permit 102982 and the Source Analysis & Technical Review for TCEQ Project No. 178224, both issued by the TCEQ;
- Attachment 2: a copy of BOP's PAL permit PAL6 issued by the TCEQ; and,
- Attachment 3: a copy of the Statement of Basis for Permit PSD-TX-102982-GHG, issued by EPA.

I hereby certify that PSD Permit PSD-TX-102982-GHG is not being used, or planned to be used, for any regulatory compliance or enforcement purposes, and that the information contained in this rescission request is factual and correct.

If you have any questions about the information provided, please contact me at benjamin.m.hurst@exxonmobil.com, or (281) 834-7728. I appreciate your time and effort on this matter.

Sincerely,

Benjamin M. Hurst
Environmental Section Supervisor

Attachment 1

- TCEQ Minor NSR Permit No. 102982
- TCEQ Construction Permit Data Analysis & Technical Review for Project 178224

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Exxon Mobil Corporation
Authorizing the Construction and Operation of
Baytown Olefins Plant
Located at **Baytown, Harris County, Texas**
Latitude 29° 45′ 0″ Longitude 95° 1′ 0″

Permit: 102982

Issuance Date: FEB 18 2014

Renewal Date: February 18, 2024

Bryan W. Shaw
For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)]
2. **Voiding of Permit**. A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification**. The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)]
9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.

Special Conditions

Permit Number 102982

1. This permit authorizes chemical manufacturing operations for a facility located at 3525 Decker Drive, Baytown, Harris County, Texas.

2. This permit covers only those sources of emissions listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates" (MAERT), and those sources are limited to the emission limits and other conditions specified in that table.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (EPA) regulations on Standards of Performance for New Stationary Sources promulgated in Title 40 Code of Federal Regulations Part 60 (40 CFR Part 60):

   A. Subpart A, General Provisions.

   B. Subpart Kb, Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for Which Construction, Reconstruction, or Modification Commenced After July 23, 1984;

   C. Subpart VVa, Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for Which Construction, Reconstruction, or Modification Commenced After November 7, 2006;

   D. Subpart NNN, Standards of Performance for Volatile Organic Compound (VOC) Emissions From Synthetic Organic Chemical Manufacturing Industry (SOCMI) Distillation Operations;

   E. Subpart RRR, Standards of Performance for Volatile Organic Compound Emissions from Synthetic Organic Chemical Manufacturing Industry (SOCMI) Reactor Processes; and

   F. Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.

4. These facilities shall comply with all applicable requirements of EPA regulations on National Emission Standards for Hazardous Air Pollutants in 40 CFR Part 61:

   A. Subpart A, General Provisions.

   B. Subpart J, National Emission Standards for Equipment Leaks (Fugitive Emission Sources) of Benzene;

   C. Subpart V, National Emission Standards for Equipment Leaks (Fugitive Emission Sources); and

D. Subpart FF, National Emission Standard for Benzene Waste Operations.

5. These facilities shall comply with all applicable requirements of the EPA regulations on National Emission Standards for Hazardous Air Pollutants for Source Categories in 40 CFR Part 63:

A. Subpart A, General Provisions.

B. Subpart XX, National Emission Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations; and

C. Subpart YY, National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards.

6. If any condition of this permit is more stringent than the applicable regulations in Special Condition Nos. 3, 4, and 5, then for the purposes of complying with this permit, the permit shall govern and be the standard by which compliance shall be demonstrated.

Emission Standards and Operational Specifications

7. The furnaces [Emission Point Numbers (EPNs) XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST] shall be designed and operated in accordance with the following requirements:

A. Fuel fired in the furnaces shall contain no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf).

B. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for each furnace. The monitored data shall be reduced to an hourly average flow rate at least once every day, using a minimum of four equally-spaced data points from each one-hour period. Each monitoring device shall be calibrated at a frequency in accordance with the manufacturer's specifications, or equivalent, or at least annually, whichever is more frequent, and shall be accurate to within 5 percent. In lieu of monitoring fuel flow, the permit holder may monitor stack exhaust flow using the flow monitoring specifications of Title 40 of the Code of Federal Regulations Part 60 (40 CFR Part 60), Appendix B, Performance Specification 6 or 40 CFR Part 75, Appendix A.

C. Emissions from EPN BOPXXFURNACE (EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST and XXHF01-ST) shall not exceed the following:

(1) 0.015 pounds nitrogen oxides (NO_x) per million Btu (lb NO_x/MMBtu) at higher heating value (HHV) on a 24-hour rolling average;

(2) 0.010 lb NO_x/MMBtu HHV on a 12-month rolling average;

(3) 50 parts per million by volume, dry (ppmvd) carbon monoxide (CO) corrected to 3 percent oxygen on a 12-month rolling average; and

(4) 15 ppmvd ammonia (NH_3) corrected to 3 percent oxygen on a one-hour rolling average.

D. Compliance with the limits in Special Condition No. 7.C shall be demonstrated for the average of all operating furnaces, EPN BOPXXFURNACE, except as specified in Special Condition No. 21.

E. The requirements in this condition and the initial demonstration of compliance requirements in Special Condition No. 25 shall apply once the furnaces are operational after a shakedown period not to exceed 180 days.

8. During decoking events, cyclonic scrubbers shall achieve a particulate matter removal efficiency of at least 95%. There shall be no visible emissions exceeding 20 percent in any six-minute period as determined using U.S. Environmental Protection Agency (EPA) Test Method 22.

A. The decoking vents covered by this permit shall not operate unless control devices and associated equipment are maintained in good working order and operating. All decoking vents will be inspected for visible emissions once per day during decoking mode. Records shall be maintained of all inspections and maintenance performed on decoking drum cyclone and ductwork.

B. The minimum steam flow rate into each decoking drum shall be continuously monitored and be recorded at least once an hour during decoking mode. The minimum steam flow rate shall be 45,000 lb/hr.

C. The steam flow meter shall be calibrated at a frequency in accordance with the manufacturer's specifications, or equivalent, or at least annually, whichever is more frequent, and shall be accurate to within 10 percent.

9. The decoking facilities shall be evaluated to demonstrate compliance with the Special Conditions and MAERT prior to commencement of operation. The evaluation procedures shall be submitted for approval to the Office of Air, Air Permits Division.

10. The elevated flare (EPN FLAREXX1) shall be designed and operated in accordance with the following requirements:

   A. The flare system shall be designed such that the combined assist gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions.

   Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements.

   B. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications or equivalent.

   C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. This shall be ensured by the use of steam assist to the flare, as appropriate.

   D. The permit holder shall install a continuous flow monitor and composition analyzer that provide a record of the vent stream flow and composition to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour.

   The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg. The initial calibration of the flow monitor shall demonstrate the flow monitor accuracy specification of ±5.0%, at flow rates equivalent to 30%, 60%, and 90% of monitor full scale. Annual calibrations of the flow monitor thereafter shall be per manufacturer specification, or equivalent.

   Calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000 (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month for HRVOC species, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR §60.18(f)(3) as amended through October 17, 2000 (65 FR 61744).

As an alternative to the calibration requirements for the continuous flow monitor and composition analyzer, the requirements for flares in 30 TAC Chapter 115 Subchapter H Division 1 (highly-Reactive Volatile Organic Compounds – Vent Gas Control) as amended to be effective December 23, 2004 (29 TexReg 11623) may be used.

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12 month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §60.18(f) shall be recorded at least once every 15 minutes.

11. The multi-point ground flare (EPN FLAREXX2) shall be designed and operated in accordance with the following requirements:

A. The flare system shall be designed such that the combined assist gas and waste stream to each flare meets the 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity under normal, upset, and maintenance flow conditions.

Flare testing per 40 CFR § 60.18(f) may be requested by the appropriate regional office to demonstrate compliance with these requirements.

B. The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermocouple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications or equivalent.

C. The flare shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. This shall be ensured by the use of pressure assist to the flare.

D. The permit holder shall install a continuous flow monitor, composition analyzer and pressure monitor that provide a record of the vent stream flow composition and pressure to the flare. The flow monitor sensor and analyzer sample points shall be installed in the vent stream as near as possible to the flare inlet such that the total vent stream to the flare is measured and analyzed. Readings shall be taken at least once every 15 minutes and the average hourly values of the flow and composition shall be recorded each hour.

The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, temperature monitor shall be ±2.0% at absolute temperature, and pressure monitor shall be ±5.0 mm Hg. The initial calibration of the flow monitor shall demonstrate the flow monitor accuracy specification of ±5.0%, at flow rates equivalent to 30%, 60%, and 90% of monitor full scale. Annual calibrations of the flow monitor thereafter shall be per manufacturer specification, or equivalent.

Calibration of the analyzer shall follow the procedures and requirements of Section 10.0 of 40 CFR Part 60, Appendix B, Performance Specification 9, as amended through October 17, 2000 (65 FR 61744), except that the multi-point calibration procedure in Section 10.1 of Performance Specification 9 shall be performed at least once every calendar quarter instead of once every month, and the mid-level calibration check procedure in Section 10.2 of Performance Specification 9 shall be performed at least once every calendar week instead of once every 24 hours. The calibration gases used for calibration procedures shall be in accordance with Section 7.1 of Performance Specification 9. Net heating value of the gas combusted in the flare shall be calculated according to the equation given in 40 CFR §60.18(f)(3) as amended through October 17, 2000 (65 FR 61744).

As an alternative to the calibration requirements for the continuous flow monitor and composition analyzer, the requirements for flares in 30 TAC Chapter 115 Subchapter H Division 1 (highly-Reactive Volatile Organic Compounds – Vent Gas Control) as amended to be effective December 23, 2004 (29 TexReg 11623) may be used.

The monitors and analyzers shall operate as required by this section at least 95% of the time when the flare is operational, averaged over a rolling 12 month period. Flared gas net heating value and actual exit velocity determined in accordance with 40 CFR §60.18(f) shall be recorded at least once every 15 minutes.

12. The emergency generators and fire water pumps engines shall be designed and operated in accordance with the following conditions:

A. The firewater pump diesel engines (EPN DIESELXXFW) and emergency generators (EPN DIESELXX) are each authorized to fire diesel fuel containing not more than 0.3 weight percent sulfur and is limited to a maximum of 52 hours of engine testing annually.

B. Any operation in excess of the times specified in Special Condition No. 12.A is subject to reporting as required by 30 TAC § 122.

13. The cooling tower (EPN BOPXXCT) shall be designed and operated in accordance with the following conditions:

A. The total dissolved solids (TDS) concentration and the recirculation rate shall be used to demonstrate compliance with the limits in the MAERT.

B. The holder of this permit shall monitor the conductivity of the cooling water at a monitoring point in the recirculating water of the cooling tower, and record these conductivity readings on a no less than weekly basis. Each conductivity measurement shall be converted to TDS concentration in ppmw using the conversion factor established in accordance with Special Condition No. 13.E.

C. The holder of this permit shall monitor the flow rate of the recirculating water of the cooling tower, and record these flow rate values on a no less than hourly basis.

D. The permit holder shall use the following equation to determine Total Dissolved Solids (TDS) concentration in cooling tower from conductivity measurement:

TDS = Conductivity x Conversion Factor (CF_{TDS})

Where:

TDS = Total dissolved solids concentration of the cooling water (ppmw)

Conductivity = Conductivity of cooling water (micromho per centimeter [μmho/cm])

Conversion Factor (CF_{TDS}) = Factor to convert conductivity measurement to TDS concentration (ppmw per μmho/cm)

E. The holder of this permit shall perform sampling to establish the relationship between TDS and conductivity that shall be used by the permit holder to demonstrate compliance with the MAERT. A cooling water sample shall be collected in each of the three calendar months following the facility startup and a conductivity and TDS analysis shall be performed for each of the three samples in order to establish the actual cooling water conductivity to TDS conversion factor. The conductivity and TDS analyses shall be performed in accordance with "Standard Methods for the Examination of Water and Wastewater" Method 2510 (Conductivity) and Method 2540 (Solids). An average conversion factor and standard deviation based on the three values shall be determined from the cooling water sample results. Additional sampling to adjust the conversion factor is allowed with approval from the Texas Commission on Environmental Quality (TCEQ) Regional Office.

The permit application TDS/conductivity conversion factor of 0.67 may be used initially until a site specific demonstrated value is determined.

F. Within 30 days after completion of the sampling as specified in Special Condition No. 13.E above, copies of the sampling report shall be submitted to the TCEQ Regional Office.

G. The VOC associated with cooling tower water shall be monitored at least monthly with an approved air stripping system, or equivalent for the purpose of detecting leaks of VOC into the cooling water.

When leaks are detected, the appropriate equipment shall be maintained so as to minimize fugitive VOC emissions from the cooling tower. Faulty equipment shall be repaired at the earliest opportunity, but no later than the next scheduled shutdown of the process unit in which the leak occurs. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained at the plant site and cover at least the two-year trailing period. The records shall be made available upon request to TCEQ personnel or any local air pollution control program having jurisdiction.

H. Cooling tower drift eliminators must have manufacturer's design assurance of 0.0005% drift or less, and shall be maintained and inspected at least annually with a record of the inspection and all repairs.

14. VOC storage tanks are subject to the following requirements:

A. The control requirements specified in paragraphs B-E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.50 psia at the maximum feed temperature or 95°F, whichever is greater, or (2) to storage tanks smaller than 25,000 gallons.

B. An internal floating deck or "roof" or equivalent control shall be installed in all tanks. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof: (1) a liquid-mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal.

C. An open-top tank containing a floating roof (external floating roof tank) which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

D. For any tank equipped with a floating roof, the permit holder shall perform the visual inspections and seal gap measurements as specified in Title 40 Code of Federal Regulations § 60.113b (40 CFR § 60.113b) Testing and Procedures (as amended at 54 FR 32973, Aug. 11, 1989) to verify fitting and seal integrity. Records shall be maintained of the dates seals were inspected and seal gap measurements made, results of inspections and measurements made (including raw data), and actions taken to correct any deficiencies noted.

E. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650 dated November 1, 1998, or an equivalent degree of flotation, except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

F. Uninsulated tank exterior surfaces exposed to the sun shall be painted white, aluminum, or an equivalent light color, except for labels, logos, etc. not to exceed 15 percent of the exterior surface area. Storage tanks must be equipped with permanent submerged fill pipes.

G. As an alternative to the control requirements of Special Condition Nos. 14.B through 14.F, the tank vent may be routed for destruction in a combustion device, such as EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, XXHF01-ST, FLAREXX1 and FLAREXX2.

H. The permit holder shall maintain a record of tank throughput for the previous month and the past consecutive 12 month period for each tank.

15. Piping, Valves, Connectors, Pumps, Agitators, and Compressors - 28VHP

Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

A. The requirements of paragraphs F and G shall not apply (1) where the Volatile Organic Compound (VOC) has an aggregate partial pressure or vapor pressure of less than 0.044 pounds per square inch, absolute (psia) at 68°F or (2) operating pressure is at least 5 kilopascals (0.725 psi) below ambient pressure. Equipment excluded from this condition shall be identified in a list or by one of the methods described below to be made readily available upon request.

The exempted components may be identified by one or more of the following methods:

(1) piping and instrumentation diagram (PID);

(2) a written or electronic database or electronic file;

(3) color coding;

(4) a form of weatherproof identification; or

(5) designation of exempted process unit boundaries.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute (ANSI), American Petroleum Institute (API), American Society of Mechanical Engineers (ASME), or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical. New and reworked buried connectors shall be welded.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Difficult-to-monitor and unsafe-to-monitor valves, as defined by Title 30 Texas Administrative Code Chapter 115 (30 TAC Chapter 115), shall be identified in a list to be made readily available upon request. The difficult-to-monitor and unsafe-to-monitor valves may be identified by one or more of the methods described in subparagraph A above. If an unsafe-to-monitor component is not considered safe to monitor within a calendar year, then it shall be monitored as soon as possible during safe-to-monitor times. A difficult-to-monitor component for which quarterly monitoring is specified may instead be monitored annually.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. Gas or hydraulic testing of the new and reworked piping connections at no less than operating pressure shall be performed prior to returning the components to service or they shall be monitored for leaks using an approved gas analyzer within 15 days of the components being returned to service. Adjustments shall be made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk-through.

Each open-ended valve or line shall be equipped with an appropriately sized cap, blind flange, plug, or a second valve to seal the line. Except during sampling, both valves shall be closed. If the isolation of equipment for hot work or the removal of a component for repair or replacement results in an open ended line or valve, it is exempt from the requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder must complete either of the following actions within that time period;

(1) a cap, blind flange, plug, or second valve must be installed on the line or valve; or

(2) the open-ended valve or line shall be monitored once for leaks above background for a plant or unit turnaround lasting up to 45 days with an approved gas analyzer and the results recorded. For all other situations, the open-ended valve or line shall be monitored once within the 72 hour period following the creation of the open ended line and monthly thereafter with an approved gas analyzer and the results recorded. For turnarounds and all other situations, leaks are indicated by readings of 500 ppmv and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve.

F. Accessible valves shall be monitored by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. If a relief valve is equipped with rupture disc, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity.

A check of the reading of the pressure-sensing device to verify disc integrity shall be performed at least quarterly and recorded in the unit log or equivalent. Pressure-sensing devices that are continuously monitored with alarms are exempt from recordkeeping requirements specified in this paragraph. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

The gas analyzer shall conform to requirements listed in Method 21 of 40 CFR part 60, appendix A. The gas analyzer shall be calibrated with methane. In addition, the response factor of the instrument for a specific VOC of interest shall be determined and meet the requirements of Section 8 of Method 21. If a mixture of VOCs is being monitored, the response factor shall be calculated for the average composition of the process fluid. A calculated average is not required when all of the compounds in the mixture have a response factor less than 10 using methane. If a response factor less than 10 cannot be achieved using methane, then the instrument may be calibrated with one of the VOC to be measured or any other VOC so long as the instrument has a response factor of less than 10 for each of the VOC to be measured.

Replacements for leaking components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump, compressor, and agitator seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with an automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump, compressor, and agitator seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. A first attempt to repair the leak must be made within 5 days and a record of the attempt shall be maintained.

I. A leaking component shall be repaired as soon as practicable, but no later than 15 days after the leak is found. If the repair of a component would require a unit shutdown that would create more emissions than the repair would eliminate, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging within 15 days of the detection of the leak. A listing of all components that qualify for delay of repair shall be maintained on a delay of repair list. The cumulative daily emissions from all components on the delay of repair list shall be estimated by multiplying by 24 the mass emission rate for each component calculated in accordance with the instructions in 30 TAC 115.782 (c)(1)(B)(i)(II). The calculations of the cumulative daily emissions from all components on the delay of repair list shall be updated within ten days of when the latest leaking component is added to the delay of repair list. When the cumulative daily emission rate of all components on the delay of repair list times the number of days until the next scheduled unit shutdown is equal to or exceeds the total emissions from a unit shutdown as calculated in accordance with 30 TAC 115.782 (c)(1)(B)(i)(I), the TCEQ Regional Manager and any local programs shall be notified and may require early unit shutdown or other appropriate action based on the number and severity of tagged leaks awaiting shutdown. This notification shall be made within 15 days of making this determination.

J. Records of repairs shall include date of repairs, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of instrument monitoring shall indicate dates and times, test methods, and instrument readings. The instrument monitoring record shall include the time that monitoring took place for no less than 95% of the instrument readings recorded. Records of physical inspections shall be noted in the operator's log or equivalent.

K. Alternative monitoring frequency schedules of 30 TAC § 115.352 - 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable National Emission Standard for Hazardous Air Pollutants (NESHAPS) and does not constitute approval of alternative standards for these regulations.

16. Alternative requirements for the equipment specified in Special Condition No. 14:

A. In addition to the methods identified in Special Condition No. 14.A, exempted components may be identified by process flow diagrams that exhibit sufficient detail to identify major pieces of equipment, including major process flows to, from, and within a process unit. Major equipment includes, but is not limited to, columns, reactors, pumps, compressors, drums, tanks, and exchangers.

B. In lieu of the requirements specified in Special Condition No. 14.E, new and reworked piping connections may be monitored for leaks using an approved gas analyzer within 30 days of the components being returned to service.

C. As an alternative to comparing the daily emission rate of the components on the delay of repair (DOR) list to the total emissions from a unit shutdown per the requirements of Special Condition No. 14, Subparagraph I, the cumulative hourly emission rate of all components on the DOR list may be compared to ten percent of the fugitive short term allowable on the Maximum Allowable Emission Rate Table in order to determine if the TCEQ Regional Director and any local program is to be notified. In addition, the hourly emission rates of each specific compound on the DOR list must be less than ten percent of the speciated hourly fugitive emission rate of the same compound.

17. Additional Flange Monitoring - 28CNTQ

A. All non-insulated flanges in gas/vapor and/or light liquid service shall be monitored quarterly with an approved gas analyzer in accordance with Special Condition Nos. 15.F through 15.J.

B. In lieu of the monitoring frequency specified in paragraph A, flanges may be monitored on a semiannual basis if the percent of flanges leaking for two consecutive quarterly monitoring periods is less than 0.5 percent. Flanges may be monitored on an annual basis if the percent of flanges leaking for two consecutive semiannual monitoring periods is less than 0.5 percent. If the percent of flanges leaking for any semiannual or annual monitoring period is 0.5 percent or greater, the facility shall revert to quarterly monitoring until the facility again qualifies for the alternative monitoring schedules previously outlined in this paragraph.

18. The permit holder shall maintain the piping and valves in NH_3 service as follows:

A. Audio, olfactory, and visual checks for NH_3 leaks within the operating area shall be made once per shift.

B. As soon as practicable, following the detection of a leak, plant personnel shall take one or more of the following actions:

(1) Locate and isolate the leak, if necessary.

(2) Commence repair or replacement of the leaking component.

(3) Use a leak collection or containment system to control the leak until repair or replacement can be made if immediate repair is not possible.

Planned Maintenance, Startup and Shutdown (MSS)

19. The holder of this permit shall minimize emissions during planned maintenance, start-up and shutdown (MSS) activities by operating the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

20. Allowable emissions for planned MSS activities associated with the facilities authorized by this permit are contained in Permit No. 3452, unless specified otherwise in this permit.

21. The emissions limits that are identified in Special Conditions No. 7.C(1) through 7.C(4) do not apply during the following planned MSS activities for furnaces (EPN BOPXXFURNACE):

    A. Hot Steam Standby Mode, defined as the period when the furnace is firing at 50% or less of the maximum allowable firing rate and no hydrocarbon feed is being charged to the furnace.

    B. Decoking Mode, defined as the period starts when air is introduced to the furnace for the purpose of decoking and ends when air is removed from the furnace.

    C. Start-up Mode, defined as the period beginning when fuel is introduced to the furnace and ending when the SCR catalyst bed reaches its stable operating temperature. A planned startup for each furnace is limited to 24 hours at 25% or less of the maximum allowable firing rate, except during startups requiring refractory dry out which is limited to 72 hours at 25% or less of the maximum allowable firing rate.

    D. Shutdown Mode, defined as the period beginning when the SCR catalyst bed first drops below its stable operating temperature and ending when the fuel is removed from the furnace.

    E. Feed in Mode, defined as the period beginning when hydrocarbon feed is introduced to the furnace and ending when the furnace reaches 70% of the maximum allowable firing rate.

    F. Feed out Mode, defined as the period beginning when a furnace drops below 70% of the maximum allowable firing rate and ending when hydrocarbon feed is isolated from the furnace.

22. Upon commencement of operation, the total hours of operation for the ground flare (EPN FLAREXX2) are limited to 160 hours in a rolling 12-month period.

Continuous Demonstration of Compliance

23. The permit holder shall install, calibrate, and maintain a continuous emission monitoring system (CEMS) to measure and record the in-stack concentration of NO_x and CO from the furnaces (EPNs XXAF01 through XXHF01).

    A. The CEMS shall meet the design and performance specifications, pass the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 9, Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60), Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ Office of Air, Air Permits Division for requirements to be met.

    B. Section (1) below applies to sources subject to the quality-assurance requirements of 40 CFR Part 60, Appendix F; section (2) applies to all other sources:

        (1) The permit holder shall assure that the CEMS meets the applicable quality-assurance requirements specified in 40 CFR Part 60, Appendix F, Procedure 1. Relative accuracy exceedances, as specified in 40 CFR Part 60, Appendix F, Subpart 5.2.3 and any CEMS downtime shall be reported to the appropriate TCEQ Regional Manager, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Manager.

        (2) The system shall be zeroed and spanned daily, and corrective action taken when the 24-hour span drift exceeds two times the amounts specified in the applicable Performance Specification Nos. 1 through 9, 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days.

            Each monitor shall be quality-assured at least quarterly using Cylinder Gas Audits (CGA) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, Section 5.1.2, with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted). An equivalent quality-assurance method approved by the TCEQ may also be used. Successive quarterly audits shall occur no closer than two months.

All CGA exceedances of ±15 percent accuracy or 5 ppm, whichever is greater, indicate that the CEMS is out of control.

C. The monitoring data shall be reduced to 1-hour average concentrations at least once every day, using a minimum of four equally-spaced data points from each one-hour period. The individual average concentrations shall be reduced to units of the permit allowable emission rate in the MAERT and Special Condition 7 at least once every week as follows:

Emissions calculations based on measured concentrations and exhaust flow rate shall be used to convert the 1-hour average concentration from the CEMS to lb/MMBtu, ppmvd, and lb/hr to demonstrate compliance with the NO_x and CO emission limits in Special Condition 7 and the MAERT. Exhaust flow rate may be monitored directly or calculated by monitoring fuel flow and using EPA Test Method 19.

(1) All monitoring data and quality-assurance data shall be maintained by the source. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

(2) The appropriate TCEQ Regional Office shall be notified at least 15 days prior to any required RATA in order to provide them the opportunity to observe the testing.

(3) Quality-assured (or valid) data must be generated when the furnace is operating except during the performance of a daily zero and span check. Loss of valid data due to periods of monitor break down, out-of-control operation (producing inaccurate data), repair, maintenance, or calibration may be exempted provided it does not exceed 5 percent of the time (in hours) that the furnace operated over the previous calendar year. The measurements missed shall be estimated using engineering judgment and the methods used recorded. Options to increase system reliability to an acceptable value, including a redundant CEMS, may be required by the TCEQ Regional Manager.

24. The NH_3 concentration in each Exhaust Stack (EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST and XXHF01-ST) shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH_3 slip is only required on days when the SCR unit is in operation.

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected in accordance with Special Condition No. 7.C(4).

B. As an approved alternative, the NH_3 slip may be measured using a sorbent or stain tube device specific for NH_3 measurement in the 5 to 10 ppm range. The frequency of sorbent or stain tube testing shall be daily for the first 60 days of operation, after which, the frequency may be reduced to weekly testing if operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR unit and when operation of the SCR unit has been proven successful with regard to controlling NH_3 slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. These results shall be recorded and used to determine compliance with Special Condition No. 7.C(4).

C. As an approved alternative to sorbent or stain tube testing or an NH_3 CEMS, the permit holder may install and operate a second NO_x CEMS probe located between the firebox and the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with Special Condition No. 7.C(4).

D. If the sorbent or stain tube testing indicates an ammonia slip concentration which exceeds 5 parts per million (ppm) at any time, the permit holder shall begin NH_3 testing by either the Phenol-Nitroprusside Method, the Indophenol Method, or EPA Conditional Test Method (CTM) 27 on a quarterly basis in addition to the weekly sorbent or stain tube testing. The quarterly testing shall continue until such time as the SCR unit catalyst is replaced; or if the quarterly testing indicates NH_3 slip is 4 ppm or less, the Phenol-Nitroprusside/Indophenol/CTM 27 tests may be suspended until sorbent or stain tube testing again indicate 5 ppm NH_3 slip or greater. These results shall be recorded and used to determine compliance with Special Condition No. 7.C(4).

E. As an approved alternative to sorbent or stain tube testing, NH_3 CEMS, or a second NO_x CEMS, the permit holder may install and operate a dual stream system of NO_x CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS, and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x

CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with Special Condition No. 7.C(4).

F. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Regional Director.

Initial Demonstration of Compliance

25. The permit holder shall perform stack sampling and other testing as required to establish the actual pattern and quantities of air contaminants being emitted into the atmosphere from the furnaces (EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST and XXHF01-ST) to demonstrate compliance with the MAERT. The permit holder is responsible for providing sampling and testing facilities and conducting the sampling and testing operations at his expense. Sampling shall be conducted in accordance with the appropriate procedures of the Texas Commission on Environmental Quality (TCEQ) Sampling Procedures Manual and the U.S. Environmental Protection Agency (EPA) Reference Methods.

Requests to waive testing for any pollutant specified in this condition shall be submitted to the TCEQ Office of Air, Air Permits Division. Test waivers and alternate/equivalent procedure proposals for Title 40 Code of Federal Regulation Part 60 (40 CFR Part 60) testing which must have EPA approval shall be submitted to the TCEQ Regional Director.

A. The appropriate TCEQ Regional Office shall be notified not less than 45 days prior to sampling. The notice shall include:

(1) Proposed date for pretest meeting.

(2) Date sampling will occur.

(3) Name of firm conducting sampling.

(4) Type of sampling equipment to be used.

(5) Method or procedure to be used in sampling.

(6) Description of any proposed deviation from the sampling procedures specified in this permit or TCEQ/EPA sampling procedures.

(7) Procedure/parameters to be used to determine worst case emissions during the sampling period.

The purpose of the pretest meeting is to review the necessary sampling and testing procedures, to provide the proper data forms for recording pertinent data, and to review the format procedures for the test reports. The TCEQ Regional Director must approve any deviation from specified sampling procedures.

(a) Air contaminants emitted from the furnaces to be tested include (but are not limited to) NO_x, SO_2, CO, PM_{10}, $PM_{2.5}$, VOC and NH_3.

(b) Sampling shall occur within 60 days after achieving the maximum operating rate, but no later than 180 days after initial start-up of the facilities and at such other times as may be required by the TCEQ Executive Director. Requests for additional time to perform sampling shall be submitted to the appropriate regional office.

(c) The facility being sampled shall operate at a minimum of 80 percent of the design firing rate during stack emission testing. These conditions/parameters and any other primary operating parameters that affect the emission rate shall be monitored and recorded during the stack test. Any additional parameters shall be determined at the pretest meeting and shall be stated in the sampling report. Permit conditions and parameter limits may be waived during stack testing performed under this condition if the proposed condition/parameter range is identified in the test notice specified in paragraph A and accepted by the TCEQ Regional Office. Permit allowable emissions and emission control requirements are not waived and still apply during stack testing periods.

During subsequent operations, if the firing rate is more than 10 percent higher than the firing rate during the previous stack test, stack sampling shall be performed at the new operating conditions within 120 days. This sampling may be waived by the TCEQ Air Section Manager for the region.

(d) Copies of the final sampling report shall be forwarded to the offices below within 60 days after sampling is completed. Sampling reports shall comply with the attached provisions entitled "Chapter 14, Contents of Sampling Reports" of the TCEQ Sampling Procedures Manual. The reports shall be distributed to the appropriate TCEQ Regional Office and each local air pollution control program, as required.

Recordkeeping

26. The permit holder shall maintain the following records electronically or in hard copy format for at least five years. These records shall be used to demonstrate compliance with the Special Conditions and the limits specified in the MAERT:

   A. Gas fuel usage for each furnace as required by Special Condition No. 7.B. Records from CEMs or monitoring/testing to demonstrate compliance with the limits in Special Condition No. 7.C.

   B. Records of decoke vent inspections and maintenance as required by Special Condition No. 8.A.

   C. Records of steam flow rate and steam flow meter calibration as required in Special Condition Nos 8.B and 8.C.

   D. Record of pilot flame presence as specified in Special Condition Nos. 10.B and 11.B. Records of vent stream flow and composition to flares EPNs FLAREXX1 and FLAREXX2 as required by Special Condition Nos. 10.D and 11.D.

   E. Records of testing hours for firewater pump diesel engines (EPNs DIESELXXFW01 through DIESELXXFW02) and emergency generators (EPNs DIESELXX01, DIESELXX02 and DIESELXX03) to demonstrate compliance with Special Condition No. 12.

   F. Records of TDS concentration and recirculating water flow rate in the cooling tower (EPN BOPXXCT) as required by Special Condition No. 13.

   G. Records of tank seal inspections as required by Special Condition No. 14.D.

   H. Records demonstrating compliance with the requirements of 28VHP as specified in Special Condition No. 15.

   I. Records of planned MSS activities and hours to demonstrate compliance with Special Condition No. 21.C for the furnaces (EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST and XXHF01-ST).

   J. Record of operation of the multi-point ground flare (EPN FLAREXX2) to demonstrate compliance with Special Condition No. 22.

   K. Records of quality assurance calibration for the CEMs as required by Special Condition No. 23.

L. Records of stack tests completed in accordance with Special Condition No. 25.

Alternate Means of Control (AMOC)

27. If a request for an AMOC is granted by the regulating authority (TCEQ or EPA) for the multi-point ground flare (EPN FLAREXX2), the requirements of the approved AMOC shall supersede the requirements of Special Condition No. 11. The permit holder shall incorporate these conditions into the permit through an alteration no later than 90 days after approval of the AMOC.

Plantwide Applicability Limit (PAL)

28. Emissions from sources and activities authorized by this permit shall be included in the compliance demonstration for PAL6.

Date: FEB 18 2014

Emission Sources - Maximum Allowable Emission Rates

Permit Number 102982

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
BOPXXFURNACE	BOP-XX Furnace Vent Cap (6)	NO_x	44.56	155.58
		SO_2	2.47	5.16
		CO	2609.78	609.49
		PM	16.53	65.31
		PM_{10}	16.53	65.31
		$PM_{2.5}$	16.53	65.31
		NH_3	47.54	74.01
		H_2SO_4	0.19	0.39
		VOC	22.66	47.26
BOPXXDECOKE	BOP-XX Furnace Decoke Cap (7)	CO	630.76	126.15
		PM	53.12	10.62
		PM_{10}	45.84	9.17
		$PM_{2.5}$	39.68	7.94
FLAREXX1	Elevated Flare	NO_x	22.24	75.54
		SO_2	7.97	17.27
		CO	160.64	193.78
		VOC	371.90	104.59

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
FLAREXX2	Multi-Point Ground Flare	NO_x	2309.32	54.29
		SO_2	233.32	7.47
		CO	3742.46	87.98
		VOC	3991.46	68.07
BOPXXFLARE (8)	BOP-XX Flare System Cap (8)	NO_x		75.54
		SO_2		17.27
		CO		193.78
		VOC		104.59
BOPXXCT	BOP-XX Cooling Tower	PM	3.29	14.43
		PM_{10}	0.89	3.92
		$PM_{2.5}$	<0.01	0.02
		VOC (5)	78.06	34.19
BOPXXFUG	BOP-XX Fugitives (5)	VOC	7.56	33.10
		NH_3	2.00	8.76
ACETCONVXX	Acetylene Converter Regeneration Vent	CO	3.80	0.23
		VOC	19.00	1.69
XXZTK05	Equalization Tank	VOC	0.11	0.44
XXZTK11	Compressor Wash Oil Tank	VOC	0.50	1.13
XXZLTK16	Emergency Generator Diesel Storage Tank 1	VOC	0.03	0.06
XXZLTK17	Emergency Generator Diesel Storage Tank 2	VOC	0.03	0.06
XXZLTK18	Emergency	VOC	0.03	0.06

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
	Generator Diesel Storage Tank 3			
XXZLTK19	Firewater Pump Diesel Storage Tank 1	VOC	0.03	0.06
XXZLTK20	Firewater Pump Diesel Storage Tank 2	VOC	0.03	0.06
DIESELXX	Backup Generator Engines (9)	NO_x	52.30	2.61
		SO_2	0.03	<0.01
		CO	22.13	1.11
		PM	2.82	0.14
		PM_{10}	2.82	0.14
		$PM_{2.5}$	2.82	0.14
		VOC	2.84	0.14
DIESELXXFW	Firewater Booster Pump Engines (10)	NO_x	37.20	1.86
		SO_2	0.71	0.04
		CO	8.02	0.40
		PM	0.87	0.04
		PM_{10}	0.87	0.04
		$PM_{2.5}$	0.87	0.04
		VOC	25.91	1.30

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source name. For fugitive sources, use area name or fugitive source name.
(3) VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
NO_x - total oxides of nitrogen
SO_2 - sulfur dioxide

Emission Sources - Maximum Allowable Emission Rates

PM	- total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10}	- total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$	- particulate matter equal to or less than 2.5 microns in diameter
CO	- carbon monoxide
NH_3	- ammonia

(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.

(5) Emission rate is an estimate and is enforceable through compliance with the applicable special condition(s) and permit application representations.

(6) BOPXXFURNACE includes EPNs XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST and XXHF01-ST.

(7) BOPXXDECOKE includes EPNs XXAB-DEC, XXCD-DEC, XXEF-DEC, XXGH-DEC.

(8) BOPXXFLARE includes EPNs FLAREXX1 and FLAREXX2.

(9) DIESELXX includes EPNs DIESELXX01, DIESELXX02, and DIESELXX03.

(10) DIESELXXFW includes EPNs DIESELXXFW1 and DIESELXXFW2.

Date: FEB 18 2014

Construction Permit
Source Analysis & Technical Review

Company	**Exxon Mobil Corporation**	Permit Number	**102982**
City	**Baytown**	Project Number	**178224**
County	**Harris**	Account Number	**HG-0228-H**
Project Type	**Initial**	Regulated Entity Number	**RN102212925**
Project Reviewer	**Mr. Kyle Virr**	Customer Reference Number	**CN600123939**
Site Name	**Baytown Olefins Plant**		

Project Overview

ExxonMobil Chemical Company (ExxonMobil) operates the Baytown Olefins Plant (BOP) in Houston, Harris County. They submitted this application to authorize a new ethylene production unit within the plant. The process will involve construction of eight new ethylene cracking furnaces and associated equipment, including cooling towers and flares, Although the new production unit will operate independently of the existing BOP operations, there will be some shared utilities, which were included in the review of this project.

The ExxonMobil Baytown Olefins Plant currently operates under Flexible Permit No. 3452, PSDTX302M2 and PAL6. ExxonMobil has established Plantwide Applicable Limits (PALs) for Volatile Organic Compounds (VOC), Nitrogen Oxides (NO_x), Particulate Matter (PM), Sulfur Dioxide (SO_2), Carbon Monoxide (CO) and Sulfuric Acid (H_2SO_4) in an amendment to Flexible Permit No. 3452 issued on August 24, 2005. The emissions associated with this permit will be included in the established PAL limits with no increases to any of the established PAL limits; therefore, no federal applicability review for this project is required.

Emission Summary

Air Contaminant	Proposed Allowable Emission Rates (tpy)
PM	90.54
PM_{10}	78.58
$PM_{2.5}$	73.45
VOC	224.14
NO_x	235.59
CO	931.16
SO_2	22.47
H_2SO_4	0.39
NH_3	82.77

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	June 26, 2013
Compliance period:	September 1, 2007 – August 31, 2012
Site rating & classification:	20.63 – Satisfactory
Company rating & classification:	11.61 – Satisfactory
If the rating is 40<RATING<45, what was the outcome, if any, based on the findings in the formal report:	N/A
Has the permit changed on the basis of the compliance history or rating?	No

EM-122-1

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Date Application Received:	May 22, 2012
	Date Administratively Complete:	May 30, 2012

Rule Citation	Requirement	
	Small Business Source?	No
	Date Leg Letters mailed:	May 30, 2012
39.603	Date Published:	June 22, 2012
	Publication Name:	*Baytown Sun*
	Pollutants:	Organic compounds, nitrogen oxides, sulfur dioxide, carbon monoxide, ammonia, sulfuric acid and particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less
	Date Affidavits/Copies Received:	July 2, 2012
	Is bilingual notice required?	Yes
	Language:	Spanish
	Date Published:	June 22, 2012
	Publication Name:	*El Perico*
	Date Affidavits/Copies Received:	July 2, 2012
	Date Certification of Sign Posting / Application Availability Received:	July 31, 2012
39.604	Public Comments Received?	Yes
	Hearing Requested?	Yes
	Meeting Request?	No
	Date Response to Comments sent to OCC:	June 28, 2013
	Consideration of Comments:	
	Is 2nd Public Notice required?	Yes
39.419	Date 2nd Public Notice/Preliminary Decision Letter Mailed:	April 9, 2013
39.413	Date Cnty Judge, Mayor, and COG letters mailed:	April 9, 2013
	Date Federal Land Manager letter mailed:	NA
39.605	Date affected states letter mailed:	NA
39.603	Date Published:	April 16, 2013
	Publication Name:	*The Baytown Sun*
	Pollutants:	Organic compounds, nitrogen oxides, sulfur dioxide, carbon monoxide, ammonia, sulfuric acid and particulate matter with diameters of 10 microns or less and 2.5 microns or less
	Date Affidavits/Copies Received:	April 25, 2013
	Is bilingual notice required?	Yes
	Language:	Spanish
	Date Published:	April 16, 2013
	Publication Name:	*El Perico*
	Date Affidavits/Copies Received:	April 25, 2013

Rule Citation	Requirement	
	Date Certification of Sign Posting / Application Availability Received:	**May 22, 2013**
	Public Comments Received?	**Yes**
	Meeting Request?	**Yes**
	Date Meeting Held:	**Meeting Denied**
	Hearing Request?	**Yes**
	Date Hearing Held:	**Preliminary Hearing July 8, 2013**
	Request(s) withdrawn?	
	Date Withdrawn:	
	Consideration of Comments:	**Changes made to the draft permit in response to comments are detailed below**
39.421	Date RTC, Technical Review & Draft Permit Conditions sent to OCC:	**June 28, 2013**
	Request for Reconsideration Received?	
	Final Action:	
	Are letters Enclosed?	

Construction Permit & Amendment Requirements - 30 TAC Chapter 116 Rules

Rule Citation	Requirement	
116.111(a)(2)(G)	Is the facility expected to perform as represented in the application?	Yes
116.111(a)(2)(A)(i)	Are emissions from this facility expected to comply with all TCEQ air quality Rules & Regulations, and the intent of the Texas Clean Air Act?	Yes
116.111(a)(2)(B)	Emissions will be measured using the following method:	**Continuous Emissions Monitoring System, Engineering Calculations**
	Comments on emission verification:	No
116.111(a)(2)(D)	Subject to NSPS?	Yes
	Subparts **A, Kb, VVa, NNN, RRR, & IIII**	
116.111(a)(2)(E)	Subject to NESHAP?	Yes
	Subparts **A, J, V, & FF**	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	Yes
	Subparts **A, XX, & YY**	
116.111(a)(2)(H)	Is nonattainment review required?	No
	Is the site located in a nonattainment area?	Yes
	Is the site a federal major source for a nonattainment pollutant?	Yes
	Is the project a federal major source for a nonattainment pollutant by itself?	No
	Is the project a federal major modification for a nonattainment pollutant?	No
	Did the project emission increases for nonattainment pollutant minus the two-year average actual emissions trigger netting?	**No. Project is within limits of PAL6**
	If yes, attach Table 1N & 9N. If no, explain:	
	Is the contemporaneous increase significant?	NA
	If the contemporaneous increase is significant a nonattainment review is required.	
116.111(a)(2)(I)	Is PSD applicable?	No
	Is the site a federal major source (100/250 tons/yr)?	Yes
	Is the project a federal major source by itself?	No
	Is the project a federal major modification?	No
	Did project emission increases, without decreases, for pollutant of concern, minus the two-year average actual emissions trigger netting?	NA

Rule Citation	Requirement	
	Was the contemporaneous increase significant?	NA
	If yes, explain:	
	Is the change excluded by 40 CFR 52.21(b)(2)(iii)?	NA
	If yes, explain:	
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?	No
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:	
116.140 - 141	Permit Fee: $ 75,000 Fee certification:	R228494

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement	
122.10(13)(A)	Is the site a major source under FCAA Section 112(b)?	Yes
122.10(13)(C)	Does the site emit 100 tons or more of any air pollutant?	Yes
122.10(13)(D)	Is the site a non-attainment major source?	Yes
122.602	**Periodic Monitoring (PM) applicability:** Periodic monitoring is performed through the following: Furnaces – fuel flow, NH_3 slip, CEMs for CO and NO_x. Furnaces decoking – steam flow. Flares – pilot flame, flow and composition of waste gas streams. Cooling towers – TDS, conductivity, and recirculation rate. Floating roof storage tanks – tank seal inspections. Fugitives – 28VHP and 28CNTQ for VOC, AVO for NH_3	
122.604	**Compliance Assurance Monitoring (CAM) applicability:** The flare is subject to 60.18 and will comply with the heating value and velocity requirements. (An AMOC has been submitted requesting use of a sonic flare instead of a 60.18 compliant flare for FLAREXX2.) The furnaces are required to be stack tested and will be equipped with a CEMs for CO and NO_x.	

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	12	Rachel Price-Taylor Nathan Chenaux	Update references to match current numbering. Editorial comments (typographical errors, etc.). Update Chapter 14 requirements to match most recent version. Add PM back half condensable language for testing and/or monitoring.
City:	Baytown	NA	No comments received
County:	Harris	NA	No comments
Toxicology:		Ross E. Jones	Impacts are acceptable
Compliance:		NA	No comments received
Impacts		Justin Cherry	Predicted impacts are acceptable
Legal:		Alexis Lorick	Various comments in response to comments received during public notice.
Comment resolution and/or unresolved issues:	Updated references and incorporate editorial corrections. Updated Chapter 14 requirements. Did not include PM condensable requirements since there is no performance testing or monitoring for PM_{10} or $PM_{2.5}$. All legal comments were resolved.		

Process/Project Description

ExxonMobil is expanding their Baytown Olefins Plant (BOP) by constructing a new ethylene production unit. This is a stand-alone unit but will rely on existing plant utilities. The site operates under PAL6, which is not being amended with this action.

Process Description

ExxonMobil will construct eight (8) new steam cracking furnaces and recovery equipment. The major pieces of recovery equipment include a quench tower, caustic wash facilities, a process gas compressor and interstage coolers, a chiller train, a refrigeration system, a deethanizer, an ethylene/ethane (C_2) splitter, and a demethanizer. The new facilities will process ethane to produce ethylene and other products. The ethane recovered from the process is recycled to the feed stream. The furnaces will fire natural gas or blended fuel gas consisting of imported natural gas and tail gas (a recycle stream resulting from an initial separation of methane and hydrogen during the chilling step within the demethanizer system).

During the cracking operation, coke (molecular carbon) gradually builds on the inside walls of the furnace tubes, impeding heat transfer. About every 30 days, the furnace must be taken down and coke removed through oxidation and spalling. The coke fines are disengaged from the decoking effluent in the decoke drum, and emissions are controlled through cyclonic separators at the decoke vents (EPNs: XXAB-DEC through XXGH-DEC).

The combined furnace effluent flows into the Quench Tower where it is cooled with quench water. The majority of the dilution steam and some of the heavier hydrocarbons are condensed and exit the tower bottoms. Cooled cracked gases from the tower overhead are caustic scrubbed and compressed. The Quench Tower bottoms stream is pyrolysis water that contains trace amounts of hydrogen sulfide, organic acids, phenols, and some heavy hydrocarbons. A stripper removes the hydrocarbons from the quench (pyrolysis) water stream that will be used for dilution stream. The heavier hydrocarbons removed from quench water are sent to the base plant for recovery.

The Recovery Section consists of process gas compression, ammonia removal, caustic scrubbing, and dry feeding; deethanizing and acetylene conversion; feed chilling and demethanizing; and ethylene recovery.

Caustic water wash towers are located between compressor stages, where carbon dioxide (CO_2) and hydrogen sulfide (H_2S) are removed in stages of caustic scrubbing. Spent caustic is oxidized in a wet air oxidation unit prior to neutralization with sulfuric acid and then sent to the wastewater treatment system. Gases from the oxidation unit are combusted to minimize VOC emissions.

The deethanizer separates the hydrocarbons with two or less carbon atoms from heavier hydrocarbons. The overhead stream is sent to the Acetylene Converters (EPN ACETCONVXX) where acetylene is converted to ethylene and ethane. Emissions for the vent are based on testing done by METCO on the existing BOP acetylene converter regeneration vent (EPN ND-08 within permit 3452). During the test, the vent gas was tested for total hydrocarbons (THC) and was sampled for speciation of the organic compounds present in the vent gas. Due to the infrequent nature of this process and minimal emissions, no add-on control is proposed. The bottoms product from the converter is sent to the BOP depropanizer within the existing BOP plant.

The demethanizer system separates ethylene from lighter components. A tail gas stream consisting of hydrogen and methane is produced. This stream can be further processed to purify and recover the hydrogen, or can be routed to the fuel gas system.

Ethylene and ethane are fractionated in the C_2 splitter to produce ethylene. The residual ethane is recycled to the steam cracking furnaces where it is mixed with fresh feed.

Support Operations

EM-122-5

A flare system consisting of an elevated flare and a multi-point ground flare will be constructed. The elevated flare will control routine waste streams. The multi-point ground flare will be used for intermittent streams. The elevated flare is designed to meet 40 CFR 60.18. The multi-point ground flare does not meet 40 CFR 60.18 due to high exit velocity.

ExxonMobil submitted a request for an alternate means of control (AMOC) on December 12,2012 to approve use of this flare as an alternate to a flare designed to meet 40 CFR §60.18. If the AMOC is not approved prior to start of construction, ExxonMobil will install a flare that is 40 CFR 60.18 compliant.

A cooling tower (EPN: BOPXXCT) will be constructed to provide process heat removal and supply cooling water to the project. The tower will be a multi-cell, induced draft, counter-flow type cooling tower. Compliance will be demonstrated by measuring of flow rate and VOC concentration for VOC emission rates, and flow rate and TDS (using conductivity as surrogate) for particulate matter emission rates. ExxonMobil derived PM_{10} and $PM_{2.5}$ fractions based on the published paper, "Calculating Realistic PM_{10} Emissions from Cooling Towers", Joel Reisman and Gordon Frisbie (undated).

For PM and $PM_{2.5}$, the maximum emission rates were based on a maximum design TDS of 5,650 ppmw. PM_{10} emission rates were based on a TDS of 3,918 ppmw, which ExxonMobil represents will result in the maximum PM_{10} emission rate. Ongoing compliance will be determined with the assumption that 39.14% of total PM from cooling towers is PM_{10} and 0.20% of total PM is $PM_{2.5}$.

Wastewater will be collected and stored within the equalization tank (EPN XXZTK05) which is a vertical tank equipped with an internal floating roof. The collected wastewater will be conveyed via enclosed piping to the existing BOP wastewater treatment plant, which is authorized in Flexible Permit No. 3452.

Several new storage tanks will be constructed for storage of materials such as slop oil, diesel fuel, wastewater, ammonia, compressor wash oil, lube oil, caustic, spent caustic, sulfuric acid, methanol, various additives, and bleach.

Three (3) backup generator diesel engines and two (2) firewater booster pump diesel engines will also be installed (EPNs: DIESELXX01 – DIESELXX03, and DIESELXXFW01 – DIESELXXFW02). Operation of these engines is limited to testing only and will not exceed 52 hours per year for each engine.

Other Affected Sources in Other Permits

In addition to the new sources, the project will rely on existing plant utilities.

Existing upstream sources affected by this proposed plant expansion are steam generation equipment. ExxonMobil is proposing the addition of duct burners to the heat recovery steam generation section of the gas turbine generator train 5 (Train 5) to provide supplemental heat to the turbine exhaust stream, thereby generating incremental steam for use at BOP. Train 5 (EPN HRSG05) is located within the base plant at BOP and authorized under Permit No. 3452. Train 5 is equipped with a selective catalytic reduction unit for NO_x control. An appropriate update for Permit No 3452 will be submitted; however, an increase in the flexible permit cap will not be requested.

Existing downstream sources affected by this proposed plant expansion are the wastewater treatment facility, and the BOP Depropanizer. The wastewater generated from this proposed expansion will be handled by the existing wastewater treatment facility. Hydrocarbons with more than two carbon atoms collected from the Deethanizer will be routed to the existing BOP Depropanizer. According to ExxonMobil, there will be no increase in allowable emissions from the existing plant facilities due to the operation of this proposed expansion.

Plantwide Applicability Limit (PAL)

ExxonMobil established a PAL for PM, VOC, NO_x, CO, SO_2, H_2SO_4 and NH_3 as part of a permit amendment in 2005. They have operated under PAL6 and have submitted semi-annual reports as demonstration of complying with PAL6 on a rolling 12-month average as required by Special Condition No. 21 of Permit No. 3452. They are not increasing any PAL limits because of this project and will continue to operate the entire Baytown Operating Plant within the established PAL limits.

Permit Conditions

SC	Requirements
1-2	Boilerplate
3-6	Federal requirements

SC	Requirements
7	Furnace monitoring requirements, concentration limits. Includes shakedown provision allowing up to 180 days for furnaces to become operations before testing and monitoring requirements apply.
8-9	Furnace decoking monitoring requirements. Requires a compliance demonstration prior to commencement of operation. ExxonMobil will submit their plan to TCEQ for approval. This is required since there are no testing requirements and the design is not finalized at the time of the permit issuance.
10-11	Boilerplate flare conditions with flow and composition monitoring requirements.
12	Emergency generator and fire water pump engines requirements limiting authorized activities to testing only (up to 52 hours per year each).
13	Cooling tower monitoring requirements which allows for conductivity as a surrogate for TDS, requires establishing correlation factors, and requires monitoring of recirculation rates.
14	Storage tank requirements. As an alternative to a floating roof, allows for control of tanks (vp less than 0.5 psia) to be controlled by existing control device.
15	28VHP
16	Exceptions to 28VHP. Allows use of process flow diagram to identify exempted components. Allows for 30 days for leaking components to be analyzed after being returned to service (to be consistent with all other existing monitoring requirements at the site.) Allows for delay of repair if total hourly rate of all DOR components is less than 10% of the fugitive short-term emission rate on MAERT.
17	28CNTQ
18	AVO for NH_3
19-20	MSS requirements. Refers to MSS authorized under Permit NO. 3452.
21	Defines furnace operations that are exempt from the concentration requirements in SC 7, including hot standby, decoking, start-up, shutdown, feed-in, and feed-out
22	Limits ground flare operation to 160 hours per rolling 12-month period after commencement of operation.
23	NO_x and CO CEMs for furnaces.
24	NH3 monitoring options.
25	Initial stack testing requirements for furnaces.
26.	Recordkeeping requirements (references other conditions within permit).
27.	Allows for use of AMOC in lieu of SC11 for ground flare.
28.	Reference to include this permit as part of PAL6 compliance demonstration

Changes in Response to Comments

In response to comments received during the first and second notice public comment period, the following changes were made to the draft permit:

- Special Condition No. 8 was changed from a 30 percent opacity limitation to a 20 percent opacity limitation in order to comply with 30 TAC §111.111(a)(1)(B).
- Special Condition No. 25.A.(7)(a) has been updated to provide an initial demonstration of compliance for all PAL pollutants.
- Special Condition No. 28 has been added to include this permit as part of the PAL6 compliance demonstration.
- Footnote (5) on the Maximum Allowable Emission Rate Table (MAERT) was moved within the cooling tower entry from the Source Name column to the Contaminant Name column for VOC.

Pollution Prevention, Sources, Controls and BACT- [30 TAC 116.111(a)(2)(C)]

Furnace Section

The furnace section will use low NO_x burners and selective catalytic reduction (SCR) during normal operation to reduce NO_x emissions. NO_x will be limited to <0.01 lb/MMBtu on a 12-month rolling average, and <0.015 lb/MMBtu on a rolling 24-hr average. CO emissions will be limited to 50 ppm at 3% O_2 on a 12-month rolling average. Collateral ammonia emissions (used in the SCR) will be limited to 10 ppmv at 3 % O_2. Formation of SO_2 and H_2SO_4 will be limited by using only low-sulfur fuel gas to fire the furnaces. This meets or exceeds current BACT.

Furnace Decoking

Coke formation will be minimized using good combustion and maintenance practices. Cyclonic separators will be used to control particulate emissions at a 95% capture efficiency during the decoking process. This meets current BACT.

JUL - 2 2013

Cooling Towers
The proposed cooling tower will undergo monthly VOC, weekly conductivity and hourly flow rate monitoring in the cooling water. PM will be limited using drift eliminators with a total drift of <0.0005%. This meets or exceeds current BACT for cooling towers.

Flare System
The proposed flare system will use low-sulfur natural gas for pilot flame. The flare system is designed with a destruction rate efficiency (DRE) of 99% for carbon compounds containing 2 to 3 carbon atoms, and 98% DRE for compounds containing 4 carbon atoms or more. This meets current BACT.

Storage Tanks
Tank XXZTK11 is a 13,900 gallon, vertical, fixed-roof tank with bottom fill used to store steam cracked gas oil at 0.013 psia. It will be painted white and have submerged fill.

Tank XXZTK05 is a 782,465 gallon, cone-roof tank with internal floating roof used to store wastewater at 0.36 psia. The internal floating roof will have a liquid-mounted primary seal and a rim mounted secondary seal. It will be painted white and have submerged fill.

The remaining tanks (XXZTK16, XXZTK17, XXZTK18, XXZTK19, and XXZTK20) are horizontal, fixed-roof tanks of 500 gallons used for storing Diesel for use in the emergency generator and firewater booster pump engines. They will be white in color with submerged fill. This meets BACT for tanks.

Diesel Engines
Diesel engines used for emergency power generation and firewater pumps will be fueled with only low-sulfur diesel fuel (<0.3 wt percent) to limit SO_2 emissions. The use of engines with a low annual capacity factor and proper maintenance will be used to limit VOC, NO_x and CO emissions. This permit only authorizes the routine testing of the engines. This meets current BACT for diesel engines.

Fugitives
Fugitive emissions are estimated at greater than 33 tons per year. Leak detection and repair (LDAR) program 28VHP and 28CNTQ are proposed. This meets current BACT for fugitives.

Ammonia Service
Leaks from components in NH_3 service will be minimized by implementation of an audio, visual, and olfactory (AVO) program. An AVO check for ammonia leaks will be performed twice per shift. This meets current BACT for ammonia service.

Wastewater
Wastewater collected in the equalization tank is routed via enclosed piping to the existing BOP wastewater treatment facility (EPN WWTBIOX in Flexible Permit No. 3452). This is BACT for wastewater.

Acetylene Converter
The acetylene converter vent is not continuous and has minimal emissions (less than 100 lbs/day). No control is BACT.

Impacts Evaluation - 30 TAC 116.111(a)(2)(J)

Was modeling conducted?	**Yes**	Type of Modeling:	**Aermod**
Will GLC of any air contaminant cause violation of NAAQS?			**No**
Is this a sensitive location with respect to nuisance?			**No**
[§116.111(a)(2)(A)(ii)] Is the site within 3000 feet of any school?			**No**
Additional site/land use information: The Baytown Olefins Plant is located in a highly industrialized area of Baytown, Harris County. The Plant is surrounded by other similar chemical and refining facilities.			

Summary of Modeling Results

ExxonMobil modeled off-property impacts of criteria pollutants and speciated VOCs using AERMOD for all new sources associated with the proposed project. (All other existing modified sources were represented as not increase allowable emissions; therefore additional modeling was not required). After review of the modeling results, the ADMT on January 29, 2013 declared that the modeling analysis was acceptable for all review types and pollutants.

In May 2013, in response to comments received during the second public notice period, ExxonMobil provided additional project modeling that included the additional duct burners which will be required for additional steam generation from HRSG5 to be authorized by Permit 3452 through a separate future permitting action. The revised modeling was reviewed and ADMT was issued on May 29, 2013 which declared that the modeling analysis including the proposed duct burners continued to be acceptable.

The following summary of NAAQS impacts includes all sources for this project, including the proposed duct burners.

Pollutant	Averaging Time	GLC_{max} (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	2.2	7.8
SO_2	3-hr	5.8	25
SO_2	24-hr	1.9	5
SO_2	Annual	0.03	1
PM_{10}	24-hr	3.1	5
$PM_{2.5}$(2)	24-hr	2.2	1.2
$PM_{2.5}$(2)	Annual	0.2	0.3
NO_2(1)	1-hr	7.48	7.5
NO_2	Annual	0.5	1
CO	1-hr	683	2000
CO	Annual	425	500

(1) Short-term NO2 was evaluated considering the emergency generators (testing only), fire water pump engines (testing only) and ground flare (<160 hours per year) as intermittent sources.
(2) The U.S. Court of Appeals vacated the $PM_{2.5}$ SIL in 2013; however, EPA has provided guidance that does not preclude use of the $PM_{2.5}$ SIL entirely. This was taken into consideration in the review.

Since the project emissions resulted in predicted impacts of $PM_{2.5}$ were greater than the de minimis levels, the sitewide emissions of $PM_{2.5}$ were evaluated including background data from the EPA AIRS monitor 482010058 located at 7210 ½ Bayway Drive, Baytown, Harris County against the 24-hr standard and determined to be acceptable:

Pollutant	Averaging Time	GLC_{max} (µg/m³)	Background (µg/m³)	Total Conc. (µg/m³)	Standard (µg/m³)
$PM_{2.5}$	24-hr	9.7	21	30.7	35

The following organic compounds were then evaluated for health effects:

Since predicted concentrations from both routine operations and planned MSS activities are less than 10% of the ESL, the following compounds dropped off at Step 9A and 9C of the MERA document: benzene, 1,3-butadiene, 1-butene, butane, n-pentane, ethyl benzene, toluene, xylene, naphthalene, isopropyl benzene, n-hexane, acetylene, and heavy VOC.

The following chemicals had exceedances and were further evaluated by for off-property health effects: Ammonia, ethylene, and light VOC. Ammonia (annual), ethylene (1-hr and annual), and light VOC (annual), the predicted off-property concentrations are less than the associated ESL, so no further review is required.

The following compounds were reviewed by the Toxicology Division under the Tier III guidelines. Impacts were found to be acceptable.

EM-122-9

Pollutant & CAS#	Averaging Time	Hours > 1 X ESL GLC_{ni}	Hours > 2 X ESL GLC_{max}
Ammonia (7664-41-7)	1-hr	5	17
Naptha, petroleum, light alkylate (light VOC) (64741-66-8)	1-hr	5	14

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**Ben Hurst**
Contacted Via:	**Email**
Date of contact:	**June 25, 2013**
Other permit(s) or permits by rule affected by this action:	**Flexible Permit No. 3452**
List permit and/or PBR number(s) and actions required or taken:	**Flexible Permit No. 3452 will be amended in a separate action to authorize duct burners on HRSG5**

Project Reviewer Date Team Leader/Section Manager/Backup Date

THE STATE OF TEXAS COUNTY OF TRAVIS JUL - 2 2013

Attachment 2

- TCEQ Plant-wide Applicability Limit Permit PAL6

Bryan W. Shaw, Ph.D., P.E., *Chairman*
Toby Baker, *Commissioner*
Zak Covar, *Commissioner*
Richard A. Hyde, P.E., *Executive Director*

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

July 7, 2014

MR BENJAMIN M HURST
ENVIRONMENTAL SECTION SUPERVISOR
EXXON MOBIL CORPORATION
PO BOX 4004
BAYTOWN TX 77522-4004

Received by GDP
7/16/14

Re: Permit Amendment
Permit Number: 3452
Renewal Date: August 24, 2015
Exxon Mobil Corporation
Exxon Mobil Chemical Baytown Olefins Plant
Baytown, Harris County
Regulated Entity Number: RN102212925
Customer Reference Number: CN600123939
Account Number: HG-0228-H
Associated Permit Numbers: PAL6 and PSDTX302M2

Dear Mr. Hurst:

This is in response to your letter received June 2, 2014 and your Form PI-1 (General Application for Air Preconstruction Permits and Amendments) concerning the proposed amendment to Flexible Permit Number 3452. We understand that you propose to install duct burners on heat recovery steam generator 5 (HRSG5). Also, this will acknowledge that your application for the above-referenced amendment is technically complete as of July 1, 2014.

In accordance with Title 30 Texas Administrative Code (TAC) §116.721(a) and based on our review, Flexible Permit Number 3452 is hereby amended. This information will be incorporated into the existing permit file. Enclosed are revised general conditions (permit face), special conditions, and a maximum allowable emission rates table. We appreciate your careful review of the special conditions of the permit and assuring that all requirements are consistently met.

This amendment will be automatically void upon the occurrence of any of the following, as indicated in 30 TAC §116.120(a):

1. Failure to begin construction of the changes authorized by this amendment within 18 months from the date of this authorization.

2. Discontinuance of construction of the changes authorized by this amendment for a period of 18 consecutive months or more.

3. Failure to complete the changes authorized by this amendment within a reasonable time.

Upon request, the executive director may grant extensions as allowed in 30 TAC §116.120(b).

Re: Permit Numbers: 3452, PSDTX302M2 and PAL6

The limitations of 30 TAC 116.120(a) do not apply to physical or operational changes allowed without an amendment under 30 TAC 116.721 of this title (relating to Amendments and Alterations). [30 TAC 116.715(c)(1)]

You may file a **motion to overturn** with the Chief Clerk. A motion to overturn is a request for the commission to review the executive director's decision. Any motion must explain why the commission should review the executive director's decision. According to 30 TAC §50.139, an action by the executive director is not affected by a motion to overturn filed under this section unless expressly ordered by the commission.

A motion to overturn must be received by the Chief Clerk within 23 days after the date of this letter. An original and 7 copies of a motion must be filed with the Chief Clerk in person, or by mail to the Chief Clerk's address on the attached mailing list. On the same day the motion is transmitted to the Chief Clerk, please provide copies to the applicant, the executive director's attorney, and the Public Interest Counsel at the addresses listed on the attached mailing list. If a motion to overturn is not acted on by the commission within 45 days after the date of this letter, then the motion shall be deemed overruled.

You may also request **judicial review** of the executive director's approval. According to Texas Health and Safety Code §382.032, a person affected by the executive director's approval must file a petition appealing the executive director's approval in Travis County district court within 30 days after the **effective date of the approval**. Even if you request judicial review, you still must exhaust your administrative remedies, which includes filing a motion to overturn in accordance with the previous paragraphs.

You are reminded that these facilities must be in compliance with all rules and regulations of the Texas Commission on Environmental Quality (TCEQ) and of the U.S. Environmental Protection Agency at all times.

If you need further information or have any questions, please contact Ms. Kristi Mills-Jurach, P.E. at (512) 239-1261 or write to the Texas Commission on Environmental Quality, Office of Air, Air Permits Division, MC-163, P.O. Box 13087, Austin, Texas 78711-3087.

Re: Permit Numbers: 3452, PSDTX302M2 and PAL6

This action is taken under authority delegated by the Executive Director of the TCEQ.

Sincerely,

Michael Wilson

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

MPW/km

Enclosures

cc: Director, Harris County, Pollution Control Services, Pasadena
Air Section Manager, Region 12 - Houston
Air Permits Section Chief, New Source Review Section (6PD-R), U.S. Environmental Protection Agency, Region 6, Dallas

Project Number: 211696

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Exxon Mobil Corporation
Authorizing the Construction and Operation of
Baytown Olefins Plant
Located at **Baytown, Harris County, Texas**
Latitude 29° 45′ 00″ Longitude 095° 01′ 00″

Permits: 3452, PAL6, and PSDTX302M2

Amendment Date : July 7, 2014

Renewal Date: August 24, 2015

For the Commission

1. **Facilities** covered by this permit shall be constructed and operated as specified in the application for the permit. All representations regarding construction plans and operation procedures contained in the permit application shall be conditions upon which the permit is issued. Variations from these representations shall be unlawful unless the permit holder first makes application to the Texas Commission on Environmental Quality (commission) Executive Director to amend this permit in that regard and such amendment is approved. [Title 30 Texas Administrative Code 116.116 (30 TAC 116.116)]
2. **Voiding of Permit.** A permit or permit amendment is automatically void if the holder fails to begin construction within 18 months of the date of issuance, discontinues construction for more than 18 months prior to completion, or fails to complete construction within a reasonable time. Upon request, the executive director may grant an 18-month extension. Before the extension is granted the permit may be subject to revision based on best available control technology, lowest achievable emission rate, and netting or offsets as applicable. One additional extension of up to 18 months may be granted if the permit holder demonstrates that emissions from the facility will comply with all rules and regulations of the commission, the intent of the Texas Clean Air Act (TCAA), including protection of the public's health and physical property; and (b)(1)the permit holder is a party to litigation not of the permit holder's initiation regarding the issuance of the permit; or (b)(2) the permit holder has spent, or committed to spend, at least 10 percent of the estimated total cost of the project up to a maximum of $5 million. A permit holder granted an extension under subsection (b)(1) of this section may receive one subsequent extension if the permit holder meets the conditions of subsection (b)(2) of this section. [30 TAC 116.120(a), (b) and (c)]
3. **Construction Progress**. Start of construction, construction interruptions exceeding 45 days, and completion of construction shall be reported to the appropriate regional office of the commission not later than 15 working days after occurrence of the event. [30 TAC 116.115(b)(2)(A)]
4. **Start-up Notification.** The appropriate air program regional office shall be notified prior to the commencement of operations of the facilities authorized by the permit in such a manner that a representative of the commission may be present. The permit holder shall provide a separate notification for the commencement of operations for each unit of phased construction, which may involve a series of units commencing operations at different times. Prior to operation of the facilities authorized by the permit, the permit holder shall identify the source or sources of allowances to be utilized for compliance with Chapter 101, Subchapter H, Division 3 of this title (relating to Mass Emissions Cap and Trade Program). [30 TAC 116.115(b)(2)(B)(iii)]
5. **Sampling Requirements**. If sampling is required, the permit holder shall contact the commission's Office of Compliance and Enforcement prior to sampling to obtain the proper data forms and procedures. All sampling and testing procedures must be approved by the executive director and coordinated with the regional representatives of the commission. The permit holder is also responsible for providing sampling facilities and conducting the sampling operations or contracting with an independent sampling consultant. [30 TAC 116.115(b)(2)(C)]

6. **Equivalency of Methods.** The permit holder must demonstrate or otherwise justify the equivalency of emission control methods, sampling or other emission testing methods, and monitoring methods proposed as alternatives to methods indicated in the conditions of the permit. Alternative methods shall be applied for in writing and must be reviewed and approved by the executive director prior to their use in fulfilling any requirements of the permit. [30 TAC 116.115(b)(2)(D)]
7. **Recordkeeping.** The permit holder shall maintain a copy of the permit along with records containing the information and data sufficient to demonstrate compliance with the permit, including production records and operating hours; keep all required records in a file at the plant site. If, however, the facility normally operates unattended, records shall be maintained at the nearest staffed location within Texas specified in the application; make the records available at the request of personnel from the commission or any air pollution control program having jurisdiction; comply with any additional recordkeeping requirements specified in special conditions attached to the permit; and retain information in the file for at least two years following the date that the information or data is obtained. [30 TAC 116.115(b)(2)(E)]
8. **Maximum Allowable Emission Rates.** The total emissions of air contaminants from any of the sources of emissions must not exceed the values stated on the table attached to the permit entitled "Emission Sources--Maximum Allowable Emission Rates." [30 TAC 116.115(b)(2)(F)]
9. **Maintenance of Emission Control.** The permitted facilities shall not be operated unless all air pollution emission capture and abatement equipment is maintained in good working order and operating properly during normal facility operations. The permit holder shall provide notification for upsets and maintenance in accordance with 30 TAC 101.201, 101.211, and 101.221 of this title (relating to Emissions Event Reporting and Recordkeeping Requirements; Scheduled Maintenance, Startup, and Shutdown Reporting and Recordkeeping Requirements; and Operational Requirements). [30 TAC 116.115(b)(2)(G)]
10. **Compliance with Rules.** Acceptance of a permit by an applicant constitutes an acknowledgment and agreement that the permit holder will comply with all rules, regulations, and orders of the commission issued in conformity with the TCAA and the conditions precedent to the granting of the permit. If more than one state or federal rule or regulation or permit condition is applicable, the most stringent limit or condition shall govern and be the standard by which compliance shall be demonstrated. Acceptance includes consent to the entrance of commission employees and agents into the permitted premises at reasonable times to investigate conditions relating to the emission or concentration of air contaminants, including compliance with the permit. [30 TAC 116.115(b)(2)(H)]
11. **This** permit may not be transferred, assigned, or conveyed by the holder except as provided by rule. [30 TAC 116.110(e)]
12. **There** may be additional special conditions attached to a permit upon issuance or modification of the permit. Such conditions in a permit may be more restrictive than the requirements of Title 30 of the Texas Administrative Code. [30 TAC 116.115(c)]
13. **Emissions** from this facility must not cause or contribute to a condition of "air pollution" as defined in Texas Health and Safety Code (THSC) 382.003(3) or violate THSC 382.085. If the executive director determines that such a condition or violation occurs, the holder shall implement additional abatement measures as necessary to control or prevent the condition or violation.
14. **The** permit holder shall comply with all the requirements of this permit. Emissions that exceed the limits of this permit are not authorized and are violations of this permit.

Special Conditions

Flexible Permit Numbers 3452, PSDTX302M2 and PAL6

Emission Standards

1. This permit authorizes emissions only from those points listed in the attached table entitled "Emission Points, Emissions Caps, and Individual Emission Limitations," and the facilities covered by this permit are authorized to emit subject to the emission rate limits on that table and other operating conditions specified in this permit.

   This permit also authorizes the emissions from the planned maintenance, startup, and shutdown (planned MSS) activities as represented in the permit amendment application dated January 5, 2008, from those points listed in the attached table entitled "Emission Sources - Maximum Allowable Emission Rates", and the facilities covered by this permit are authorized to emit subject to the emission rate limits on the maximum allowable emission rates table (MAERT) and other requirements specified in Special Condition Nos. 26 through 44.

2. Visible emissions resulting from the decoking of the cracking furnaces shall not exceed opacity of 10 percent averaged over a six-minute period, as determined by a trained observer.

   Emissions from the cogeneration trains shall not exceed 5 percent opacity as determined by the U.S. Environmental Protection (EPA) Reference Method 9.

Federal Applicability

3. These facilities shall comply with all applicable requirements of the EPA regulations in Title 40 Code of Federal Regulations (40 CFR) Part 60, Subparts A, D, Db, GG, K, Kb, VV, NNN, RRR, and YYY on Standards of Performance for New Stationary Sources promulgated for Fossil-Fuel Steam Generating Units, for Industrial Steam Generating Units, for Stationary Gas Turbines and Duct Burners, for Storage Vessels for Petroleum Liquids, for Volatile Organic Liquid Storage Vessels, for Equipment Leaks of Volatile Organic Compounds (VOC) in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI), for VOC Emissions from SOCMI Distillation Operations, for VOC Emissions from SOCMI Reactor Processes, and for control of VOC from SOCMI Wastewater

4. These facilities shall comply with all applicable requirements of the EPA regulations in 40 CFR Part 63, Subparts F, G, H, UU, WW, XX, and YY on National Emission Standards for Hazardous Air Pollutants (NESHAPS) promulgated for the SOCMI, for Process Vents, Storage Vessels, Transfer Operations, and Wastewater, for Equipment Leaks, for Heat Exchange Systems and Waste Operations, for Generic Maximum Achievable Control Technology, for Equipment Leaks, and for Storage Vessels (Tanks). **(08/05)**

5. These facilities shall comply with all applicable requirements of the EPA regulations on NESHAPS promulgated for Equipment Leaks of Benzene, for Equipment Leaks, and for Benzene Waste Operations in 40 CFR Part 61, Subparts A, J, V, and FF.

6. This permit establishes PALs for VOC, carbon monoxide (CO), nitrogen oxide (NO_x), sulfur dioxide (SO_2), sulfuric acid (H_2SO_4), and particulate matter (PM). The PALs are effective for ten years after this permit is issued. Physical changes and changes in method of operation at this site are exempt from federal New Source Review (NSR) for VOC, CO, NO_x, SO_2, H_2SO_4, and PM as long as site emissions do not exceed the PAL caps.

The permit holder shall submit a permit alteration, unless an amendment application has been made for state authorization, prior to operating any new facilities at the site that emit VOC, CO, NO_x, SO_2, H_2SO_4, or PM. The application will serve to identify the best available control technology controls as well as monitoring and recordkeeping requirements for the new facilities to be covered by the PAL. State authorization for all new facilities must be obtained prior to start of construction. Piping and piping components (valves, flanges, and pumps) are authorized by this permit to the extent that the component count and associated emissions do not exceed that identified in the flexible/PAL permit application.

Any project that requires that the PAL caps be increased will be subject to the appropriate federal NSR requirements. **(08/05)**

Operational Limitations

7. A. Non-fugitive emissions from relief valves, safety valves, or rupture discs of gases containing VOC at a concentration of greater than 1 percent are not authorized by this permit unless authorized on the MAERT. Any releases directly to atmosphere from relief valves, safety valves, or rupture discs of containing VOC at a concentration greater than 1 weight percent are not containing VOC at a concentration greater than 1 weight percent are not consistent with good practice for minimizing emissions with the exception of those emission point numbers (EPNs) listed below:

Safety relief valves that may lift in case of fire:

crude isoprene storage drum	UTK-201A
crude isoprene storage drum	UTK-201B
raffinate storage tank	UTK-202
slop oil tank	XZTK-01
slop oil tank	XZTK-02
sludge tank	XZTK-03
IGF tank	XZTK-04

hot ends tank farm	ZLTK-02A
butadiene sphere	ZTK-01A
butadiene sphere	ZTK-01B
butadiene sphere	ZTK-01C
butylene sphere	ZTK-03
C4 slop sphere	ZTK-04

The Oil Water Separator has a safety relief valve, EPN XZL-06, that may lift as a result of pump failure. The Butane Surge Drum, EPN ZD-32, has a secondary relief valve (primary venting is to a flare header). The Vent Gas System, EPN XSP-072, has a secondary relief valve (primary venting is to a furnace firebox).

B. This permit authorizes emissions from the primary and secondary base plant Flares, EPN FLARE1 and FLARE2, for the following maintenance, start-up, and shutdown activities:

(1) vinyl acetylene compressor discharge

(2) equipment clearing

(3) venting of non-condensable gases

(4) refinery gas recovery cold box wash

(5) hydrogen hot strip of steam cracked naphtha catalyst bed

(6) pipeline clearing

C. This permit authorizes emissions from the expansion Flare, EPN FLAREX, for the following maintenance, start-up, and shutdown activities:

(1) equipment clearing

(2) venting of non-condensable gases

(3) pulldown of recycle ethane vaporizer

(4) pressure swing adsorber maintenance

(5) regeneration of acetylene converter

D. These emissions are subject to the maximum allowable emission rates indicated on the MAERT. **(08/05)**

8. Fuel fired in the furnaces, turbines, duct burners and boilers is limited to pipeline-quality, sweet natural gas; refinery fuel gas; Syngas plant purge gas; plant tail gas; or any combination of these gases. **(07/14)**

Boilers A, B, C, and D shall not be fired with liquid fuel.

Flare Conditions

9. Each flare shall be designed and operated in accordance with 40 CFR § 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.

10. The Secondary Flare, FLARE2, may be used as the primary flare during maintenance of the Primary Flare, FLARE1, or may be used in conjunction with or in lieu of the primary flare in normal service.

11. The following requirements apply to the operation of the primary flare (or to the secondary flare when it is operated in place of the primary flare):

    A. The permittee shall measure rates of waste gas flow to the flares downstream of the flare knockout drum. The gas flow rate shall be accurately measured and accounted for so that a daily and a monthly total flow rate can be determined.

    B. The permittee shall obtain and analyze a sample of flare waste gas downstream of the flare knockout drum when the flare is in service. Samples must be taken and analyzed for at least 95 percent of the operating days. Samples may be grab samples. Each sample shall be analyzed by the extended gas chromatograph method to provide a complete composition of all hydrocarbons and other compounds (including carbon dioxide (CO_2), CO, hydrogen, and nitrogen) contained in the gas streams at more than 1.0 percent by weight. Individual C4s and heavier hydrocarbons contained at less than 1.0 percent by weight may be grouped in this analysis.

    C. The permittee shall calculate the monthly average VOC emissions for each month not later than the 30th day following the month for which the average is being calculated. The permittee shall apply the Texas Commission on Environmental Quality (TCEQ) flare emission factors when calculating flare air contaminant emission rates. Records of VOC emissions (pounds per month) for each month and on a rolling 12-month average shall be maintained at the plant site and cover at least the trailing two-year period. They shall be immediately available upon request to TCEQ personnel or any local air pollution control program having jurisdiction. **(08/05)**

Leak Detection and Repair Program

12. Piping, Valves, Connectors, Pumps, and Compressors in VOC Service - 28VHP

    Except as may be provided for in the special conditions of this permit, the following requirements apply to the above-referenced equipment:

    A. These conditions shall not apply (1) where the VOC has an aggregate partial pressure or vapor pressure of less than 0.044 pound per square inch, absolute (psia) at 68°F or (2) to piping and valves two inches nominal size and smaller or (3) operating pressure is at least 5 kilopascals (0.725 pound per square inch) below ambient pressure. Equipment excluded from this condition shall be identified in a list to be made available upon request.

B. Construction of new and reworked piping, valves, pump systems, and compressor systems shall conform to applicable American National Standards Institute, American Petroleum Institute (API), American Society of Mechanical Engineers, or equivalent codes.

C. New and reworked underground process pipelines shall contain no buried valves such that fugitive emission monitoring is rendered impractical.

D. To the extent that good engineering practice will permit, new and reworked valves and piping connections shall be so located to be reasonably accessible for leak-checking during plant operation. Non-accessible valves, as defined by Title 30 Texas Administrative Code (30 TAC) Chapter 115, shall be identified in a list to be made available upon request.

E. New and reworked piping connections shall be welded or flanged. Screwed connections are permissible only on piping smaller than two-inch diameter. No later than the next scheduled quarterly monitoring after initial installation or replacement, all new or reworked connections shall be gas-tested or hydraulically tested at no less than normal operating pressure and adjustments made as necessary to obtain leak-free performance. Connectors shall be inspected by visual, audible, and/or olfactory means at least weekly by operating personnel walk through.

Each open-ended valve or line shall be equipped with a cap, blind flange, plug, or a second valve. Except during sampling, the second valve shall be closed.

F. Accessible valves shall be monitored by leak checking for fugitive emissions at least quarterly using an approved gas analyzer. Sealless/leakless valves (including, but not limited to, welded bonnet bellows and diaphragm valves) and relief valves equipped with a rupture disc upstream or venting to a control device are not required to be monitored. For valves equipped with rupture discs, a pressure-sensing device shall be installed between the relief valve and rupture disc to monitor disc integrity. All leaking discs shall be replaced at the earliest opportunity but no later than the next process shutdown.

An approved gas analyzer shall conform to requirements listed in 40 CFR § 60.485(a) (b).

Replaced components shall be re-monitored within 15 days of being placed back into VOC service.

G. Except as may be provided for in the special conditions of this permit, all pump and compressor seals shall be monitored with an approved gas analyzer at least quarterly or be equipped with a shaft sealing system that prevents or detects emissions of VOC from the seal. Seal systems designed and operated to prevent emissions or seals equipped with automatic seal failure detection and alarm system need not be monitored. These seal systems may include (but are not limited to) dual pump seals with barrier fluid at higher pressure than process pressure, seals degassing to vent control systems kept in good working order, or seals equipped with an automatic seal failure detection and alarm system. Submerged pumps or sealless pumps (including, but not limited to, diaphragm, canned, or magnetic-driven pumps) may be used to satisfy the requirements of this condition and need not be monitored.

H. Damaged or leaking valves or connectors found to be emitting VOC in excess of 500 parts per million by volume (ppmv) or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired. Damaged or leaking pump and compressor seals found to be emitting VOC in excess of 2,000 ppmv or found by visual inspection to be leaking (e.g., dripping process fluids) shall be tagged and replaced or repaired.

I. Every reasonable effort shall be made to repair a leaking component, as specified in this paragraph, within 15 days after the leak is found. If the repair of a component would require a unit shutdown, the repair may be delayed until the next scheduled shutdown. All leaking components which cannot be repaired until a scheduled shutdown shall be identified for such repair by tagging. At the discretion of the TCEQ Executive Director or designated representative, early unit shutdown or other appropriate action may be required based on the number and severity of tagged leaks awaiting shutdown.

J. The results of the required fugitive instrument monitoring and maintenance program shall be made available to the TCEQ Executive Director or designated representative upon request. Records shall indicate appropriate dates, test methods, instrument readings, repair results, justification for delay of repairs, and corrective actions taken for all components. Records of physical inspections are not required unless a leak is detected.

K. Alternative monitoring frequency schedules of 30 TAC §§ 115.352 through 115.359 or National Emission Standards for Organic Hazardous Air Pollutants, 40 CFR Part 63, Subpart H, may be used in lieu of Items F through G of this condition.

L. Compliance with the requirements of this condition does not assure compliance with requirements of 30 TAC Chapter 115, an applicable New Source Performance Standard (NSPS), or an applicable NESHAPS and does not constitute approval of alternative standards for these regulations.

13. A. Flange Monitoring - In addition to the sensory-based program for flange monitoring specified in Special Condition No. 12E above, the permittee shall monitor flanges by leak-checking for fugitive emissions at least quarterly using an approved gas analyzer with a directed maintenance program. Special Condition No. 12H also applies to flange monitoring.

B. Pump and Compressor Seal Monitoring - Instead of the leak definition of 2,000 ppmv specified for instrument monitoring of pump and compressor seals in

Special Condition No. 12H above, the permittee shall use a leak definition of 500 ppmv for pump and compressor seal instrument monitoring. **(03/98)**

C. For operating areas having components in ammonia (NH_3) service, audio, olfactory, and visual checks for NH_3 shall be made once per shift within the operating area. No later than one hour following detection of a leak, plant personnel shall take the following actions: **(06/03)**

(1) Locate and isolate the leak.

(2) Commence repair or replacement of the leaking component as appropriate.

(3) Use a leak collection/containment system to control the leak until repair or replacement can be made.

Cooling Tower Monitoring

14. The VOC associated with cooling tower water shall be monitored at least monthly with an approved air stripping system, or equivalent for the purpose of detecting leaks of VOC into the cooling water. When leaks are detected, the appropriate equipment shall be maintained so as to minimize fugitive VOC emissions from the cooling tower. Faulty equipment shall be repaired at the earliest opportunity, but no later than the next scheduled shutdown of the process unit in which the leak occurs. The results of the monitoring and maintenance efforts shall be recorded, and such records shall be maintained at the plant site and cover at least the two-year trailing period. The records shall be made available upon request to TCEQ personnel or any local air pollution control program having jurisdiction. The "Headspace GC Determination of VOC in Water" method detailed in a letter provided by ExxonMobil on May 15, 1996 and approved by TCEQ in a letter dated September 12, 1996, is considered an equivalent method. **(08/05)**

15. For purposes of demonstrating compliance with the particulate matter PAL, the cooling towers (EPNs BOPCT and BOPXCT) shall be operated and monitored in accordance with the following: **(06/14)**

A. Cooling towers shall be monitored for particulate emissions using one of the following methods:

(1) Cooling water shall be sampled at least once per day for total dissolved solids (TDS); or

(2) TDS sampling may be reduced to weekly if conductivity is monitored daily and TDS is calculated using a ratio of TDS-to-conductivity (in ppmw per μmho/cm). The ratio of TDS-to-conductivity shall be determined by concurrently monitoring TDS and conductivity on a weekly basis. The permit holder may use the average of two consecutive TDS-to-conductivity ratios to calculate daily TDS; or

(3) TDS sampling may be reduced to quarterly if conductivity is monitored daily and TDS is calculated using a correlation factor established for each cooling tower. The correlation factor shall be the average of nine consecutive weekly TDS-to-conductivity ratios determined using (2) above provided the highest ratio is not more than 10% larger than the smallest ratio.

The permit holder shall validate the TDS-to-conductivity correlation factor once each calendar quarter. If the ratio of concurrently sampled TDS and conductivity is more than 10% higher or lower than the established factor, the permit holder shall increase TDS sampling to weekly until a new correlation factor can be established.

B. Cooling water sampling shall be representative of the cooling tower feed water and shall be conducted using approved methods.

(1) The analysis method for TDS shall be EPA Method 160.1, ASTM D5907, and SM 2540 C [SM - 19th edition of Standard Methods for Examination of Water]. Water samples should be capped upon collection, and transferred to a laboratory area for analysis. Annual average emission rates of PM shall be calculated using the measured TDS, a drift rate 0.01%, and either the average actual cooling water circulation rate or the design maximum circulation rate.

(2) The analysis method for conductivity shall be either ASTM D1125-95A (field or routine laboratory testing) or ASTM D1125-95B (continuous monitor). The analysis may be conducted at the sample site or with a calibrated process conductivity meter. If a conductivity meter is used, it shall be calibrated at least annually. Documentation of the method and any associated calibration records shall be maintained for a period of five years.

(3) Alternate sampling and analysis methods may be used to comply with C(1) and C(2) with written approval from the TCEQ Regional Director.

(4) Records of all instrument calibrations and test results and process measurements used for the emission calculations shall be retained.

C. Emission rates of PM shall be calculated using the measured TDS and the ratio or correlation of TDS to conductivity measurements, a drift rate of 0.01% and either the average actual cooling water circulation rate or the design maximum circulation rate may be used for all calculations. Emission records shall be updated monthly and maintained for a period of five years.

Storage of VOC and NH_3

16. A. The control requirements specified in paragraphs B through E of this condition shall not apply (1) where the VOC has an aggregate partial pressure of less than 0.5 psia at the maximum expected operating temperature or (2) to storage tanks smaller than 25,000 gallons.

B. An internal floating deck or "roof" or equivalent control shall be installed in all tanks. The floating roof shall be equipped with one of the following closure devices between the wall of the storage vessel and the edge of the internal floating roof: (1) a liquid mounted seal, (2) two continuous seals mounted one above the other, or (3) a mechanical shoe seal. Installation of equivalent control requires prior review and approval by the TCEQ Executive Director.

C. An open-top tank containing a floating roof (external floating roof tank) which uses double seal or secondary seal technology shall be an approved control alternative to an internal floating roof tank provided the primary seal consists of either a mechanical shoe seal or a liquid-mounted seal, and the secondary seal is rim-mounted. A weathershield is not approvable as a secondary seal unless specifically reviewed and determined to be vapor-tight.

D. For any tank equipped with a floating roof, the holder of this permit shall follow 40 CFR § 60.113b, Testing and Procedures, to verify seal integrity. Additionally, the permit holder shall follow 40 CFR § 60.115b, Reporting and Recordkeeping Requirements, to provide records of the dates the seals were inspected, seal integrity, and corrective actions taken.

E. The floating roof design shall incorporate sufficient flotation to conform to the requirements of API Code 650, or an equivalent degree of flotation, except that an internal floating cover need not be designed to meet rainfall support requirements and the materials of construction may be steel or other materials.

F. Uninsulated tank exterior surfaces exposed to the sun shall be white or aluminum.

G. For purposes of assuring compliance with VOC emission limitations, the holder of this permit shall maintain a monthly emissions record which describes calculated emissions of VOC from all storage tanks. The record shall include tank identification number, control method used, tank or vessel capacity in gallons, name of the material stored or loaded, VOC molecular weight, VOC monthly average temperature in degrees Fahrenheit, VOC vapor pressure at the monthly average material temperature in psia, and VOC throughput for the previous month and year-to-date. Records of VOC monthly average temperature are not required to be kept for unheated tanks which receive liquids that are at or below ambient temperatures. These records shall be maintained at the plant site for at least two years and be made available to representatives of the TCEQ upon request.

typo

H. Emissions for tanks shall be calculated using: (a) AP-42 ACompilation of Air Pollution Emission Factors@ and (b) TCEQ guidance documents. **(02/02)**

I. The service of NH_3 storage tanks represented in this permit is limited to the storage of aqueous NH_3 only. **(06/03)**

Continuous Demonstration of Compliance

17. The holder of this permit shall install, calibrate, and maintain a continuous emissions monitoring system (CEMS) to measure and record the in-stack concentration of NO_x, from the main stack of each Cracking Furnace (AF-01, BF-01, CF-01, DF-01, EF-01l, FF-01, GF-01, HF-0l, IF-01, JF-01, OF-01, QF-01, XAF-01, XBF-01, XCF-01, XDF-01, XEF-01, XFF-01, and XGF-0l) and NO_x, CO, and oxygen (O_2) or CO_2 at the exhaust stacks of the three GE-6 gas turbines, the Siemens turbine, and the GE 7 turbine. The NO_x and CO concentrations for the turbines shall be corrected for 15 percent excess O_2 and used as part of the overall compliance determination with the MAERT Caps.

A. Each CEMS shall meet the design and performance specifications, conduct the field tests, and meet the installation requirements and the data analysis and reporting requirements specified in the applicable Performance Specification Nos. 1 through 6, 40 CFR Part 60, Appendix B. If there are no applicable performance specifications in 40 CFR Part 60, Appendix B, contact the TCEQ in Austin for requirements to be met.

B. Each system shall be zeroed and spanned daily and corrective action taken when the 24 hour span drift exceeds two times the amounts specified in 40 CFR Part 60, Appendix B, or as specified by the TCEQ if not specified in Appendix B. Each gaseous monitor shall be quality-assured at least quarterly using cylinder gas audits (CGA). The CGA method to be used is contained in 40 CFR Part 60, Appendix F. Procedure 1, ' 5.1.2. An equivalent method approved by the EPA and the TCEQ may be used. Zero and span is not required on weekends and plant holidays if instrument technicians are not normally scheduled on those days, unless the monitor is required by a subpart of NSPS or NESHAPS, in which case zero and span shall be done daily without exception.

Each monitor shall be quality-assured at least quarterly in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2 with the following exception: a relative accuracy test audit (RATA) is not required once every four quarters (i.e., four successive quarterly CGA may be conducted) unless the CEMS is subject to the requirements of 40 CFR Part 60 (NSPS). For non-NSPS sources, an equivalent method approved by the TCEQ may be used.

All CGA exceedances of ±15 percent accuracy or 5 ppm, whichever is greater and any unscheduled CEMS downtime shall be reported to the appropriate TCEQ Regional Director as per requirements in 30TAC§117.345, and necessary corrective action shall be taken. Supplemental stack concentration measurements may be required at the discretion of the appropriate TCEQ Regional Director. Unscheduled CEMS downtime is any CEMS downtime not required for daily zero and span cheeks, quarterly CGAs, and annual relative accuracy test audits (RATA). Supplemental stack concentration measurements may be required at the discretion of the TCEQ Regional Director or the EPA.

C. The monitoring data shall be reduced to hourly average concentrations at least once everyday, using a minimum of four equally-spaced data points from each one-hour period. Two valid data points shall be generated during the hourly period in which zero and span is performed.

Flow rates used to convert ppmv(d) to mass emission rates in pounds per hour and lb/MMBtu may be obtained from calculations based on the firing rate of each furnace, the stack temperature of each furnace, and the percent O_2 in the exhaust stack of each furnace.

D. All hourly average and daily average monitoring data and quality-assurance data shall be maintained by the permittee for a period of at least two years and shall be made available upon request to representatives of the TCEQ. The data from the CEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

E. For NSPS sources subject to Appendix F, the appropriate TCEQ Regional Office shall be notified at least 21 days prior to any required RATA in order to provide them the opportunity to observe the testing. **(06/03)**

F. If applicable, the CEMS at the exhaust stacks of the three GE-6 gas turbines, the Siemens turbine, and the GE-7 turbine may be required to meet the design and performance specifications, conduct the field tests, and meet the installation requirements and data analysis and reporting requirements specified in the applicable performances specifications in 40 CFR Part 75, Appendix A. Title 40 CFR Part 75 is deemed an acceptable alternative to the performance specifications and quality-assurance requirements of 40 CFR Part 60.

G. The CEMS shall demonstrate 90 percent monitor data availability on a monthly basis. The percent monitor data availability shall be calculated as the total unit operating hours for which quality-assured data was recorded divided by the total unit operating hours. **(08/05)**

18. In lieu of installation and operation of a CEMS to measure and record the in-stack concentration of NO_x, from the main stacks of the Cracking Furnaces (AF-01, BF-01, CF 01, DF-01, EF-0l, FF-01, GF-01, HF-0l, IF-01, JF-01, OF-01, QF-01, XAF-01, XBF 01, XCF-01, XDF-01, XEF-01, XFF-01, and XGF-0l.) as provided in Special Condition No. 17 above, the permittee may use predictive emission monitoring system (PEMS) for demonstrating continuous compliance if it can be demonstrated to have the same or better accuracy, precision, reliability, accessibility, and timeliness as that provided by a hardware CEMS.

A generic PEMS, developed for a similarly designed cracking furnace, maybe installed at the time of commencement of operation of a furnace and used, instead of a CEMS or permanent PEMS, to predict and record the in-stack concentration or mass rate of NO_x for a period of time not to exceed six months. The PEMS may be retrained using data collected during the initial demonstration of compliance and subsequently collected test data.

All permanent PEMS must be approved by the Executive Director of the TCEQ. The permittee must petition the TCEQ Executive Director for approval to use permanent

PEMS. The petition must include results of tests conducted to demonstrate equivalent accuracy and precision of PEMS to that of a hardware CEMS.

A. If a PEMS is used to demonstrate continuous compliance, the holder of this permit shall install, calibrate, maintain, and operate flow meters to monitor and record flows of fuels being fired in the furnace(s). All other parameters necessary for PEMS operation within the acceptable performance requirements must also be monitored and recorded. In addition:

(1) The PEMS must be based on measured parameters including (but not limited to) fuel flow, steam injection rate or pressure, and excess combustion air quantity.

(2) The PEMS output as lbs of NO_x, per hour will be averaged for each calendar hour of operation. Pounds of NO_x, per MMBtu fired will be averaged for each operating day. These results shall be recorded. For purposes of this condition, operation is defined as those periods when hydrocarbons are being fed to the furnace for purposes of manufacturing olefins.

(3) The PEMS shall meet the requirements specified in 30 TAC ' 117.213(c), as applicable to the monitoring of NO_x, emissions. For the purposes of compliance with the requirements for quarterly RATA specified in ' 117.213(c)(3)(B)(I) and for the purposes of this permit only, if operating time during a calendar quarter is less than 60 days, the owner or operator may delay the RATA until the next calendar quarter; however, the RATA must be performed within 90 facility (furnace) operating days after the previous RATA was completed. A quarterly RATA may be omitted if the facility is inoperative for 90 or more successive days.

(4) The PEMS downtime summaries shall be submitted to the appropriate TCEQ Regional Director once each calendar quarter. If no downtime periods occur, this shall be so stated in the quarterly summary. Necessary corrective action shall be taken for each PEMS downtime occurrence.

(5) Within 60 days after the PEMS is developed and installed on any furnace, a RATA shall be performed. Results of testing shall be submitted to the appropriate TCEQ Regional Office within 60 days after completion of the RATA. A results summary of all criteria testing performed pursuant to 30 TAC ' 117.213(c) shall be submitted within 60 days after completion of such tests.

(6) Following the three successive RATA referenced in paragraph (3) above, a RATA must be performed every six months pursuant to 40 CFR Part 60, Appendix B, Performance Specification 2, Subsection 4.3 (pertaining to NO_x,). The RATA may be performed every 12 months if the relative accuracy in lb/MMBtu during the previous audit for the NO_x monitor is less than or equal to 7.5 percent. Any RATA exceeding 20 percent or statistical test exceeding the applicable standard shall be reported to the appropriate TCEQ Regional Director. A single RATA may be performed

when any required quarterly and semi-annual or annual RATA occur concurrently.

B. All monitoring data and all quality-assurance data shall be maintained at the plant site for a period of at least two years and shall be made available upon request to representatives of the TCEQ. The data from the CEMS or PEMS may, at the discretion of the TCEQ, be used to determine compliance with the conditions of this permit.

C. For NSPS sources subject to Appendix F, or for the demonstration of PEMS performance, the appropriate TCEQ Regional Office shall be notified at least 30 days prior to each RATA in order to provide them the opportunity to observe the testing.

D. The holder of this permit shall perform automatic sensor validation at least daily on any PEMS installed under the authority of this permit. The permittee shall develop and implement plans that will ensure proper functioning of the monitoring systems, ensure proper accuracy and calibration of all operational parameters that affect emissions and serve as input to the PEMS, and ensure continuous operation within the certified operating range.

E. A PEMS is required to provide valid emission predictions at least 95 percent of the time that the furnace being monitored is operated. **(08/05)**

19. The NH_3 concentration in the GE-7 turbine exhaust stack shall be tested or calculated according to one of the methods listed below and shall be tested or calculated according to frequency listed below. Testing for NH_3 slip is only required on days when the selective catalytic reduction (SCR) unit is in operation. **(06/03)**

A. The holder of this permit may install, calibrate, maintain, and operate a CEMS to measure and record the concentrations of NH_3. The NH_3 concentrations shall be corrected to 15 percent excess O_2 and used to determine compliance with the NH_3 emission caps outlined in the MAERT.

B. As an approved alternative, the NH_3 slip may be measured using a sorbent or stain tube device specific for NH_3 measurement in the 5 to 10 parts per million (ppm) range. The frequency of sorbent or stain tube testing shall be daily for the first 60 days of operation, after which the frequency maybe reduced to weekly testing if operating procedures have been developed to prevent excess amounts of NH_3 from being introduced in the SCR unit and when operation of the SCR unit has been proven successful with regard to controlling NH_3 slip. Daily sorbent or stain tube testing shall resume when the catalyst is within 30 days of its useful life expectancy. These results shall be recorded and used to determine compliance with the NH_3 caps in the MAERT.

C. As an approved alternative to sorbent or stain tube testing or an NH_3 CEMS, the permit holder may install and operate a second NO_x CEMS probe located between the firebox and the SCR, upstream of the stack NO_x CEMS, which may be used in association with the SCR efficiency and NH_3 injection rate to estimate NH_3 slip. This condition shall not be construed to set a minimum NO_x reduction efficiency on the SCR unit. These results shall be recorded and used to determine compliance with the NH_3 caps in the MAERT.

D. If the sorbent or stain tube testing indicates an NH_3 slip concentration which exceeds 5 ppm at any time, the permit holder shall begin NH_3 testing by either the Phenol Nitroprusside Method, the Indophenol Method, or the EPA Conditional Test Method (CTM) 27 on a quarterly basis, in addition to the weekly sorbent or stain tube testing. The quarterly testing shall continue until such time as the SCR unit catalyst is replaced; or if the quarterly testing indicates NH_3 slip is 4 ppm or less, the Phenol Nitroprusside/Indophenol/CTM 27 tests may be suspended until sorbent or stain tube testing again indicate 5 ppm NH_3 slip or greater. These results shall be recorded and used to determine compliance with the NH_3 caps in the MAERT.

E. As an approved alternative to sorbent or stain tube testing, NH_3 CEMS, or a second NO_x CEMS, the permit holder may install and operate a dual stream system of NO_x, CEMS at the exit of the SCR. One of the exhaust streams would be routed, in an unconverted state, to one NO_x CEMS and the other exhaust stream would be routed through a NH_3 converter to convert NH_3 to NO_x and then to a second NO_x CEMS. The NH_3 slip concentration shall be calculated from the delta between the two NO_x CEMS readings (converted and unconverted). These results shall be recorded and used to determine compliance with the NH_3 caps in the MAERT.

F. Any other method used for measuring NH_3 slip shall require prior approval from the TCEQ Compliance Support Division in Austin.

Recordkeeping

20. Records of the following information shall be maintained by the holder of this permit on a two-year rolling retention basis and shall be made available on request to representatives of the TCEQ, EPA, or any local air pollution control program having jurisdiction:

A. Records of any maintenance that may affect emissions performed upon the turbines or duct burners covered by this permit.

B. Hourly records of start-up and shutdown events associated with the HRSGs necessary to demonstrate compliance with the MAERT for these events.

C. Records of NH_3 emissions sampling and calculations pursuant to Special Condition No. 19. **(07/11)**

21. The holder of this permit shall report to the appropriate TCEQ Regional Office and TCEQ Executive Director on a semiannual basis, all periods of excess emissions via the 30TAC§116 PAL semiannual report and CEMS downtimes by cause via the 30TAC§117.345 semiannual report. Excess emissions are defined as emission in excess of MAERT CAP values.

22. Equipment excluded from the requirements of Special Condition No. 12A shall be identified by one of the following methods:

A. A plant site plan;

B. Color coding;

C. A written or electronic database;

D. Designation of process unit boundaries;

E. Some form of weatherproof identification; or

F. Process flow diagrams that exhibit sufficient detail to identify major pieces of equipment, including major process flows to, from, and within a process unit. Major equipment includes, but is not limited to, columns, reactors, pumps, compressors, drums, tanks, and exchangers.

Furnace Retrofits

23. Upon commencement of operation of Furnace XGF-01 (Phase H operation), retrofit of furnaces included in the flexible permit emission caps is authorized. These include: **(06/02)**

EPN CAF01-ST	Furnace AF-01
EPN CCF01-ST	Furnace CF-01
EPN CDF01-ST	Furnace DF-01
EPN CEF01-ST	Furnace EF-01
EPN CFF01-ST	Furnace FF-01
EPN CGF01-ST	Furnace GF-01
EPN CHF01-ST	Furnace HF-01
EPN CIF01-ST	Furnace IF-01
EPN CJF01-ST	Furnace JF-01
EPN COF01-ST	Furnace OF-01
EPN CQF01-ST	Furnace QF-01

Emission Cap Compliance

24. The determination of emissions to demonstrate compliance with the emission caps shall be determined as follows:

A. Fugitives - monthly emissions are to be estimated from annual calculations based on actual fugitive monitoring data.

B. Tanks - emissions are calculated monthly as specified in Special Condition No. 16.

C. Flares - emissions are determined as specified in Special Condition No. 11 along with the emission factors and destruction efficiencies used in the flexible permit application.

D. Cooling Towers - calculations based on recirculation rates and monthly monitoring data as required by Special Condition No. 14.

E. Combustion Sources - emissions for all combustion sources will be determined using CEMS data.

F. Engines - calculations will be based on engine run-time meters and emission factors used in the permit application.

G. Maintenance, startup, and shutdown (MSS) using engineering calculations appropriate for the specific start-up, shutdown, and maintenance activity listed in the MAERT, any occurrence described in MSS Case 1 or Case 2 lasting more than twelve hours will require notification to the Houston Regional Office of the TCEQ.

H. Vents and other operations equipment - emissions from vents and other facilities in operation shall be equal to the emission cap contribution for the vent or facility unless operating rates/emissions exceed those represented in the flexible permit application. In that case, emissions shall be estimated using the same methods used in the permit application.

The emissions shall be determined each month and the rolling 12-month emission total determined to demonstrate compliance with each emission cap. Calendar years may be used for VOC through the end of 2008. **(08/05)**

Plantwide Applicability Limit (PAL)

25. The compliance demonstration for the PAL limits established for the facility and documented in the MAERT for Permit No. 3452 shall be based on the following: **(06/14)**

A. Emissions determinations as described in Special Condition No. 24.

B. Cooling Towers - calculations based on monitoring as required by Special Condition No. 15.

Planned Maintenance, Start-Up and Shutdown Activities

26. Attachment A identifies inherently low emitting planned MSS activities that may be performed at the Baytown Olefins Plant. Emissions from activities identified in Attachment A shall be considered to be equal to the potential to emit represented in the permit application. The estimated emissions from the activities listed in Attachment A

must be revalidated annually. This revalidation shall consist of the estimated emissions for each type of activity and the basis for that emission estimate. **(03/11)**

Routine maintenance activities, as identified in Attachment B may be tracked through the work orders or equivalent. Emissions from activities identified in Attachment B shall be calculated using the number of work orders or equivalent that month and the emissions associated with that activity identified in the permit application.

Unless otherwise prescribed in this permit the performance of each planned MSS activity not identified in Attachments A or B and the emissions associated with it shall be recorded and include at least the following information:

A. the physical location at which emissions from the planned MSS activity occurred, including the emission point number and common name for the point at which the emissions were released into the atmosphere;

B. the type of planned MSS activity and the reason for the planned MSS activity;

C. the common name and the facility identification number, if applicable, of the facilities at which the planned MSS activity and emissions occurred;

D. the start date and time of the planned MSS activity and its duration;

E. the estimated quantity of each air contaminant, or mixture of air contaminants, emitted with the data and methods used to determine it. The emissions shall be estimated using the methods identified in the permit application, consistent with good engineering practice.

Emissions from all completed planned MSS activities shall be summed for each calendar month, and the rolling 12-month emissions shall be updated by the end of the next calendar month.

27. This permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: frac tanks, containers, vacuum trucks, facilities used for painting or abrasive blasting, portable control devices identified in Special Condition No. 37, ancillary equipment such as fugitives, consumables and controlled recovery systems. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site in the same service for more than 12 consecutive months, (b) is used solely to support planned MSS activities at the permanent site facilities, and (c) does not operate as a replacement for an existing authorized facility. This permit also authorizes emissions for the planned MSS activities summarized in Attachment C, "Planned MSS Activity Summary". **(03/11)**

28. Process equipment and facilities, with the exception of those identified in Special Condition Nos. 31, 32, and 34, and Attachment A shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements. **(03/11)**

A. Process equipment that contains liquid material with a VOC partial pressure greater than or equal to 0.044 psia at 68°F shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid.

B. If mixed phase materials must be removed from process equipment, the cleared material shall be routed to a knockout drum or equivalent to allow for managed initial phase separation. If the VOC partial pressure is greater than 0.044 psia at 68°F, any vents in the system shall be routed to a control device or a controlled recovery system. Control shall remain in place until degassing has been completed or the system is no longer vented to atmosphere.

C. All liquids from process equipment or storage vessels shall be removed to the maximum extent practical prior to opening equipment to commence degassing and/or maintenance. Liquids with a VOC partial pressure greater than or equal to 0.044 psia at 68°F shall be drained into a closed vessel unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid shall be covered or transferred to a covered vessel within one hour of being drained. After draining is complete, empty open pans may remain in use for housekeeping reasons to collect incidental drips.

D. If the VOC partial pressure is greater than or equal to 0.044 psia at 68°F, facilities (excluding those in commercial natural gas service) shall be degassed using good engineering practice to ensure air contaminants are removed from the system through the control device or controlled recovery system to the extent allowed by process equipment or storage vessel design. The facilities to be degassed shall not be vented directly to atmosphere, except as necessary to establish isolation of the work area or to monitor VOC concentration following controlled depressurization. The venting shall be minimized to the maximum extent practicable and actions taken recorded. The control device or recovery system utilized shall be recorded with the estimated emissions from controlled and uncontrolled degassing calculated using the methods that were used to determine allowable emissions for the permit application.

(1) For MSS activities identified in Attachment B, the following option may be used in lieu of (2) below. The facilities being prepared for maintenance shall not be vented directly to atmosphere, until the VOC concentration has been verified to be less than 10,000 ppmv or 10 percent of the lower explosive limit (LEL), or equivalent, per the site safety procedures.

(2) The locations and/or identifiers where the purge gas or steam enters the process equipment or storage vessel and the exit points for the exhaust gases shall be recorded. If the process equipment is purged with a gas, two system volumes of purge gas must have passed through the control device or controlled recovery system before the vent stream may be sampled to verify acceptable VOC concentration prior to uncontrolled venting. The VOC sampling and analysis shall be performed using an instrument meeting the requirements of Special Condition No. 29. The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the

sample probe or the collection system downstream of the process equipment or vessel being purged. The facilities shall be degassed to a control device or controlled recovery system until the VOC concentration is less than 10,000 ppmv or 10 percent of the lower explosive limit (LEL).

E. Gases and vapors (including vapors from residual liquids) with VOC partial pressure greater than 0.044 psia at 68°F may be vented directly to atmosphere if all the following criteria are met:

(1) It is not technically practicable to depressurize or degas, as applicable, into the process.

(2) There is not an available connection to a plant control system (flare).

(3) There is no more than 50 pounds of air contaminant to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Special Condition No. 28E, except when identified for an activity on Attachment A, must be documented when occurring as part of any MSS activity. The emissions associated with venting without control must be included in the work order or equivalent for those planned MSS activities identified in Attachment B.

29. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below. **(03/11)**

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR 60, Appendix A) with the following exceptions:

(1) The instrument shall be calibrated within 24 hours of use with a calibration gas such that the response factor of the VOC (or mixture of VOCs) to be monitored shall be less than 2.0. The calibration gas and the gas to be measured, and its approximate response factor shall be recorded.

(2) Sampling shall be performed as directed by this permit in lieu of section 8.3 of Method 21. During sampling, data recording shall not begin until after two times the instrument response time. The date and time shall be recorded, and VOC concentration shall be monitored for at least 5 minutes, and the highest stable measured VOC concentration shall be recorded. The highest measured VOC concentration shall not exceed the specified VOC concentration limit prior to uncontrolled venting.

B. Colorimetric gas detector tubes may be used to determine air contaminant concentrations if they are used in accordance with the following requirements.

(1) The air contaminant concentration measured is less than 80 percent of the range of the tube. If the maximum range of the tube is greater than the release concentration defined in (3), the concentration measured is at least 20 percent of the maximum range of the tube.

(2) The tube is used in accordance with the manufacturer's guidelines.

(3) At least 2 samples taken at least 5 minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) < release concentration.

Where the release concentration is:

(10,000)*(mole fraction of the total air contaminants present that can be detected by the tube).

The mole fraction may be estimated based on process knowledge. The release concentration and basis for its determination shall be recorded.

Records shall be maintained of the tube type, range, measured concentrations, and time the samples were taken.

C. Lower explosive limit (LEL) shall be measured with a lower explosive limit detector, with the following requirements.

(1) The detector shall be calibrated monthly with a certified pentane gas standard at 25% of the lower explosive limit (LEL) for pentane. Records of the calibration date and time and the calibration result (pass/fail) shall be maintained.

(2) A daily functionality test shall be performed on each detector using the same certified gas standard used for calibration. The LEL detector shall read no lower than 90% of the calibration gas certified value. Records of the functionality test date and time and the test result (pass/fail) shall be maintained.

(3) A certified methane gas standard equivalent to 25% of the LEL for pentane may be used for calibration and functionality tests provided that the LEL response is within 95% of that for pentane.

30. If the removal of a component for repair or replacement results in an open ended line or valve that is subject to Special Condition 12, the open ended line is exempt from any NSR permit condition requirement to install a cap, blind flange, plug, or second valve for 72 hours. If the repair or replacement is not completed within 72 hours, the permit holder shall complete either of the following within that 72-hour time period: **(03/11)**

A. Install a cap, blind flange, plug, or second valve on the line or valve; or

B. Verify that there is not a VOC leak from the open-ended line or valve. The open-ended line or valve shall be monitored at least once each week in accordance with the monitoring method requirements of Special Condition 12 except that for MSS, leaks are indicated by readings 500 ppmv above background and must be repaired within 24 hours or a cap, blind flange, plug, or second valve must be installed on the line or valve. The results of this weekly verification and any corrective actions taken shall be recorded.

31. This permit authorizes emissions from storage tanks with an internal floating roof during planned floating roof landings. Tank roofs may only be landed for changes of tank service or tank inspection/maintenance as identified in the permit application, except when the VOC vapors below the floating roof are routed to a control device or a controlled recovery system from the time the floating roof is landed until the floating roof is within 10% by volume of being refloated. This exception will not apply to tank convenience landings and such landings are not represented in the permit application. Emissions from change of service tank landings shall not exceed 10 tons of VOC in any rolling 12 month period. Tank roof landings include all operations when the tank floating roof is on its supporting legs. These emissions are subject to the maximum allowable emission rates indicated on the MAERT. The following requirements apply to tank roof landings. **(03/11)**

A. The tank liquid level shall be continuously lowered after the tank floating roof initially lands on its supporting legs until the tank has been drained to the maximum extent practicable without entering the tank. Liquid level may be maintained steady for a period of up to two hours if necessary to allow for valve lineups and pump changes necessary to drain the tank. This requirement does not apply where the vapor under a floating roof is routed to control or a controlled recovery system during this process.

B. If the VOC partial pressure of the liquid previously stored in the tank is greater than 0.044 psia at 68°F, tank refilling or degassing of the vapor space under the landed floating roof must begin within 24 hours after the tank has been drained unless the vapor under the floating roof is routed to control or a controlled recovery system during this period. Floating roof tanks with liquid capacities less than 100,000 gallons may be degassed without control if the VOC partial pressure of the standing liquid in the tank has been reduced to less than 0.02 psia prior to ventilating the tank. Controlled degassing of the vapor space under landed roofs shall be completed as follows:

(1) Any gas or vapor removed from the vapor space under the floating roof must be routed to a control device or a controlled recovery system and controlled degassing must be maintained until the VOC concentration before the inlet to the control device or controlled recovery system is less than 10,000 ppmv or 10 percent of the LEL. The locations and identifiers of vents other than permanent roof fittings and seals, control device or controlled recovery system, and controlled exhaust stream shall be recorded. There shall be no other gas/vapor flow out of the vapor space under the floating roof when degassing to the control device or controlled recovery system.

(2) The vapor space under the floating roof shall be vented using good engineering practice to ensure VOC vapors are flushed out of the tank through the control device or controlled recovery system to the extent allowed by the storage tank design.

(3) A volume of purge gas equivalent to twice the volume of the vapor space under the floating roof shall be passed through the control device or into a

controlled recovery system, before the vent stream may be sampled to verify acceptable VOC concentration. The measurement of purge gas volume shall not include any make-up air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition 29.

(4) The sampling point shall be upstream of the inlet to the control device or controlled recovery system. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the process equipment or vessel being purged.

(5) Degassing must be performed every 24 hours unless there is no standing liquid in the tank or the VOC partial pressure of the remaining liquid in the tank is less than 0.15 psia.

C. The tank shall not be opened except as necessary to set up for degassing and cleaning, or ventilated without control, until either there is no standing VOC liquid in the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. These criteria may be demonstrated in any one of the following ways.

(1) Low VOC partial pressure liquid that is soluble with the liquid previously stored may be added to the tank to lower the VOC partial pressure of the liquid mixture remaining in the tank to less than 0.02 psia. This liquid shall be added during tank degassing if practicable. The estimated volume of liquid remaining in the drained tank and the volume and type of liquid added shall be recorded. The liquid VOC partial pressure may be estimated based on this information and engineering calculations.

(2) If water is added or sprayed into the tank to remove standing VOC, one of the following must be demonstrated:

(a) Take a representative sample of the liquid remaining in the tank and verify no visible sheen using the static sheen test from 40 CFR 435 Subpart A Appendix 1.

(b) Take a representative sample of the liquid remaining in the tank and verify hexane soluble VOC concentration is less than 1000 ppmw using EPA method 1664 (may also use 8260B or 5030 with 8015 from SW-846).

(c) Stop ventilation and close the tank for at least 24 hours. When the tank manway is opened after this period, verify VOC concentration is less than 1000 ppmv through the procedure in Special Condition 29.

(3) No standing liquid verified through visual inspection.

Records shall be maintained to document the method used to release the tank under Special Condition 31.C.

D. Following a planned MSS-related floating roof landing, tanks shall be refilled in accordance with the following requirements (31.D.(1) to (3) below), unless the vapor space below the floating roof is routed to a control device or a controlled recovery system when the tank is refilled until the floating roof is within 10% by volume of being refloated. The control device or controlled recovery system used and the method and locations used to connect the control device or controlled recovery system shall be recorded. All vents from the tank being refilled shall exit through the control device.

(1) The tank shall be refilled as rapidly as practicable until the floating roof is off its legs.

(2) Only one tank with a landed floating roof can be filled at any time at a rate not to exceed 5,000 bbl/hr.

(3) The re-fill rate for Tank ZTK05 with a "landed" roof will not exceed 880 bbl/hr

E. The occurrence of each floating roof landing shall be recorded, and emissions calculated per Special Condition 26. These records shall include at least the following information:

(1) the identification of the tank and emission point number, and any control devices or recovery systems used to reduce emissions;

(2) the reason for the tank roof landing;

(3) for the purpose of estimating emissions, the date, time, and other information specified for each of the following events:

(a) the floating roof was initially landed,

(b) all liquid was pumped from the tank to the extent practical,

(c) start and completion of controlled degassing, and total volumetric flow,

(d) all standing liquid was removed from the tank or any transfers of low VOC partial pressure liquid to or from the tank including volumes and vapor pressures to reduce tank liquid VOC partial pressure to <0.02 psia,

(e) if there is liquid in the tank, VOC partial pressure of liquid, start and completion of uncontrolled degassing, and total volumetric flow,

(f) refilling commenced, liquid filling the tank, and the volume necessary to float the roof; and

(g) tank roof off supporting legs, floating on liquid;

(4) the estimated quantity of each air contaminant, or mixture of air contaminants, emitted between events c and g with the data and methods used to determine it. The emissions associated with floating roof landing activities shall be calculated using the methods described in Section

7.1.3.2 of AP 42 "Compilation of Air Pollution Emission Factors, Chapter 7 - Storage of Organic Liquids" dated November 2006 and the permit application.

32. Fixed roof storage tanks shall not be ventilated without control, until either all standing liquid has been removed from the tank or the liquid in the tank has a VOC partial pressure less than 0.02 psia. This shall be verified and documented through one of the criteria identified in Special Condition 31.C. Fixed roof tanks manways may be opened without emission controls when there is standing liquid with a VOC partial pressure greater than 0.02 psia vapor as necessary to set up for degassing and cleaning. One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. The emission control system shall meet the requirements of Special Condition 31.B.(1) through 31.B.(4) and records maintained per Special Condition 31.E.(3)c. through 31.E.(3)e., and 31.E.(4). Low vapor pressure liquid may be added to and removed from the tank as necessary to lower the vapor pressure of the liquid mixture remaining in the tank to less than 0.02 psia. **(03/11)**

33. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site: **(03/11)**

A. Vacuum pumps and blowers shall not be operated on trucks containing or while collecting liquids with a VOC partial pressure greater than or equal to 0.044 psia at 68°F unless the vacuum/blower exhaust is routed to a control device or a controlled recovery system.

B. The fill line intake shall be equipped with a "duckbill" or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

C. A daily record containing the information identified below is required for each vacuum truck in operation at the site each day.

(1) Prior to initial use, identify any liquid in the truck. Record the liquid level and document that the VOC partial pressure is less than 0.044 psia at 68°F if the vacuum/blower exhaust is not routed to a control device or a controlled recovery system. After each liquid collection, identify the liquid collected and document that the VOC partial pressure is less than 0.044 psia at 68°F psia if the vacuum exhaust is not routed to a control device or a controlled recovery system.

(2) For each liquid collection made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid collected. The reason for operating in this manner and whether a "duckbill" or equivalent was used shall be recorded. Short, incidental periods, such as those necessary to walk from the truck to the fill line intake, do not need to be documented.

(3) If the vacuum/blower exhaust is controlled with a control device other than an engine or oxidizer, VOC exhaust concentration upon commencing each collection, at the end of each collection, and at least every hour

during each collection, measured using an instrument meeting the requirements of Special Condition 29.

(4) The volume in the vacuum truck at the end of the day, or the volume unloaded, as applicable.

D. The permit holder shall determine the vacuum truck emissions each month using the daily vacuum truck records and the calculation methods utilized in the permit application. If records of the volume of liquid collected for each pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid collected with the greatest potential emissions. Rolling 12 month vacuum truck emissions shall also be determined on a monthly basis.

E. If the VOC partial pressure of all the liquids collected into the truck is less than 0.10 psia, this shall be recorded when the truck is unloaded or leaves the plant site and the emissions may be estimated as the maximum potential to emit for a truck in that service as documented in the permit application. The recordkeeping requirements in Special Condition 33.A through 33.D do not apply.

34. The following requirements apply to frac tanks, temporary tanks, and vessels used in support of MSS activities.

A. The exterior surfaces of these tanks/vessels that are exposed to the sun shall be white or aluminum effective May 1, 2013, except for labels, logos, etc. not to exceed 15% of the exterior surface area. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled.

B. These tanks/vessels must be covered and equipped with fill pipes that discharge within 6 inches of the tank/vessel bottom.

C. These requirements do not apply to vessels storing less than 100 gallons of liquid that are closed such that the vessel does not vent to atmosphere.

D. The permit holder shall maintain an emissions record which includes calculated emissions of VOC from all frac tanks during the previous calendar month and the past consecutive 12 month period. The record shall include tank identification number, dates put into and removed from service, control method used, tank capacity and volume of liquid stored in gallons, name of the material stored, VOC molecular weight, and VOC partial pressure at the estimated monthly average material temperature in psia. Filling emissions for tanks shall be calculated using the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Loading Operations" and standing emissions determined using: the TCEQ publication titled "Technical Guidance Package for Chemical Sources - Storage Tanks."

E. If the tank/vessel is used to store liquid with VOC partial pressure less than 0.044 psia at 68°F, records may be limited to the days the tank is in service and the liquid stored. Emissions may be estimated based upon the potential to emit as identified in the permit application.

35. MSS activities represented in the permit application may be authorized under permit by rule only if the procedures, emission controls, monitoring, and recordkeeping are the same as those required by this permit. **(03/11)**

36. All permanent facilities must comply with all operating requirements, limits, and representations in the permits identified in Attachment D during planned startup and shutdown unless alternate requirements and limits are identified in this permit or approved by TCEQ. Alternate requirements for emissions from routine emission points are identified below. **(03/11)**

    A. Combustion units, except as provided in Special condition 36.B below, with the exception of flares, at this site are exempt from NO_x and CO operating requirements identified in special conditions in this NSR permit during planned startup and shutdown if the following criteria are satisfied.

        (1) The maximum allowable emission rates in the permit authorizing the facility are not exceeded.

        (2) The startup period does not exceed 8 hours in duration and the firing rate does not exceed 75 percent of the design firing rate. The time it takes to complete the shutdown does not exceed 4 hours.

        (3) Control devices are started and operating properly when venting a waste gas stream.

    B. The limits identified below apply to the operations of the specified facilities during startup and shutdown.

        (1) During periods of startup, shutdown, and maintenance on the steam generator/gas turbines for trains 1, 2, 3, 4 and 5, the following conditions apply:

            (a) emissions shall not exceed those listed in the MSS limits in the MAERT (Case 1 Duct Burners Unfired and Case 2 Duct Burners Fired), see foot note (6) in the MAERT;

            (b) CO emissions are not required to comply with 30 TAC 117.310(c)(1)(A), 400 ppmv at 3% o2 on a rolling 24-hour average basis. A CO continuous emission monitor meeting the requirements of Special Condition 17 will be used to demonstrate compliance with the MAERT. During any 24-hour period in which equipment authorized by this permit and subject to 30 TAC 117.310(c) is operating in startup, shutdown or maintenance (MSS) mode, lasting a maximum of 12 hours, the maximum CO emissions will be limited to 500 parts per million by volume (ppmv) @ 15 % O_2, based on a 24-hour rolling average, instead of the 400 ppmv limitation found in 30 TAC 117.310(c), except as provided in 30 TAC 117.325. For any 24-hour period in which no MSS operations are occurring, the emission limits of 30 TAC 117.310 shall apply.

(c) NH_3 emissions must comply with MAERT limit, but are not required to comply with 30 TAC 117.310(c)(2)(B), 10 ppmv at 15% 02 on a rolling 24-hour average basis during MSS activities. Ammonia emissions are limited to 15 ppmv at 15% O_2, based on a 24-hour rolling average, lasting a maximum of 12 hours, instead of the 10 ppmv limitation found in 30 TAC 117.310(c)(2) during MSS operations, except as provide in 117.325. For any 24-hour period in which no MSS operations are occurring, the emission limits of 30 TAC § 117.300 shall apply.

(2) During periods of startup and shutdown of the combustion units (excluding the steam generator/gas turbines for trains 1, 2, 3, 4, and 5), the CO emissions must comply with MAERT limit, but are not required to comply with 30 TAC 117.310(c)(1)(A), 400 ppmv at 3% 02 on a rolling 24-hour average basis during MSS activities. A CO continuous emission monitor meeting the requirements of Special Condition 17 will be used to demonstrate compliance with the MAERT. Activities include refractory curing which has a duration of up to 72 hours and may utilize temporary vents.

C. A record shall be maintained indicating that the start and end times each of the activities identified in 36.A. and 36.B. above occur and that the requirements for each have been satisfied.

37. Control devices required by this permit for emissions from planned MSS activities are limited to those types identified in this condition. Control devices shall be operated with no visible emissions except periods not to exceed a total of five minutes during any two consecutive hours. Each device used must meet all the requirements identified for that type of control device. **(03/11)**

Controlled recovery systems identified in this permit shall be directed to an operating olefin process or to a collection system that is vented through a control device meeting the requirements of this permit condition.

A. Carbon Adsorption System (CAS).

(1) The CAS shall consist of 2 carbon canisters in series with adequate carbon supply for the emission control operation.

(2) The CAS shall be sampled downstream on the first can and the concentration recorded at least once every hour of CAS run time to determine breakthrough of the VOC. The sampling frequency may be extended using either of the following methods:

(a) It may be extended to up to 30 percent of the minimum potential saturation time for a new can of carbon. The permit holder shall maintain records including the calculations performed to determine the minimum saturation time.

(b) The permit holder may elect to extend the carbon sampling frequency to longer periods based on previous experience with carbon control of a MSS waste gas stream. The past experience must be with the same VOC, type of facility, and MSS activity. The basis for the sampling frequency shall be recorded. If the VOC concentration on the initial sample downstream of the first carbon canister following a new polishing canister being put in place is greater than 100 ppmv above background, it shall be assumed that breakthrough occurred while that canister functioned as the final polishing canister.

(3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 29.

(4) Breakthrough is defined as the highest measured VOC concentration at or exceeding 100 ppmv above background. When the condition of breakthrough of VOC from the initial saturation canister occurs, the waste gas flow shall be switched to the second canister and a fresh canister shall be placed as the new final polishing canister within four hours.

(5) Records of CAS monitoring shall include the following:

(a) Sample time and date.

(b) Monitoring results (ppmv).

(c) Canister replacement log.

(6) Single canister systems are allowed if the time the carbon canister is in service is limited to no more than 30% of the minimum potential saturation time. The permit holder shall maintain records for these systems, including the calculations performed to determine the saturation time. The time limit on carbon canister service shall be recorded and the expiration date attached to the carbon can.

(7) Liquid scrubbers may be used upstream of carbon canisters to enhance VOC capture provided such systems are closed systems and the spent absorbing solution is discharged into a closed container, vessel, or system. CAS systems equipped with an upstream liquid scrubber may be sampled once every 12 hours of CAS run time to determine breakthrough.

B. Single Carbon Adsorption or Scrubber System

As an alternative to the requirements in paragraph A.(6) and A.(7) a single liquid scrubbing or single carbon adsorption system may be used as a sole control device if the requirements below are satisfied.

(1) The exhaust to atmosphere shall be continuously monitored with a CEM. The VOC concentration shall be recorded at least once every 15 minutes when waste gas is directed to the CAS or scrubber.

(2) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 29.

(3) An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background and 2% of the system inlet concentration. Monitoring shall be performed upstream of the carbon can to demonstrate collection efficiency. The MSS activity shall be stopped as soon as possible when the VOC concentration exceeds 100 ppmv above background for more than one minute. The date and time of all alarms and the actions taken shall be recorded.

C. Thermal Oxidizer.

(1) The thermal oxidizer firebox exit temperature shall be maintained at not less than 1400°F and waste gas flows shall be limited to assure at least a 0.5 second residence time in the fire box while waste gas is being fed into the oxidizer.

(2) The thermal oxidizer exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurements shall be made at intervals of six minutes or less and recorded at that frequency.

The temperature measurement device shall be installed, calibrated, and maintained according to accepted practice and the manufacturer's specifications. The device shall have an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5°C.

(3) As an alternative to Special Condition No. 37.C. (1) the thermal oxidizer may be tested to confirm a minimum 99 weight percent destruction efficiency. The results of the test will be used to determine the minimum operating temperature and residence time. Stack Test must have been performed within the last 12 months. Stack VOC concentrations and flow rates shall be measured in accordance with applicable United States Environmental Protection Agency (EPA) Reference Methods. A copy of the test report shall be maintained with the thermal oxidizer and a summary of the testing results shall be included with the emission calculations.

(4) As an alternative to Special Condition No. 37.C.(3), the thermal oxidizer may be equipped with continuous VOC monitors (inlet and outlet). The VOC monitors shall be calibrated and maintained according to Special Condition No. 29. In order to demonstrate compliance with this requirement, inlet VOC and outlet VOC concentrations shall be measured and inlet and out let VOC mass rates shall be calculated on an hourly basis to confirm a minimum 99 weight percent destruction efficiency or an exhaust concentration not greater than 20 ppmv.

D. Internal Combustion Engine.

(1) The internal combustion engine shall have a VOC destruction efficiency of at least 99 percent.

(2) The engine must have been stack tested with propane or butane to confirm the required destruction efficiency within the past 12 months. VOC shall be measured in accordance with the applicable United States Environmental Protection Agency (EPA) Reference Method during the stack test and the exhaust flow rate may be determined from measured fuel flow rate and measured oxygen concentration. A copy of the stack test report shall be maintained with the engine. There shall also be documentation of acceptable VOC emissions following each occurrence of engine maintenance which may reasonably be expected to increase emissions including oxygen sensor replacement and catalyst cleaning or replacement. Stain tube indicators specifically designed to measure VOC concentration shall be acceptable for this documentation, provided a hot air probe or equivalent device is used to prevent error due to high stack temperature, and three sets of concentration measurements are made and averaged. Portable VOC analyzers meeting the requirements of Special Condition 29 are also acceptable for this documentation

(3) The engine shall be operated with an oxygen sensor-based air-to-fuel ratio (AFR) controller. Documentation for each AFR controller that the manufacturer's, or supplier's recommended maintenance has been performed, including replacement of the oxygen sensor as necessary for oxygen sensor-based controllers shall be maintained with the engine. The oxygen sensor shall be replaced at least quarterly in the absence of a specific written recommendation. The engine must have been stack tested within the past 12 months in accordance with part (2) of this condition.

The test period may be extended to 24 months if the engine exhaust is sampled once an hour when waste gas is directed to the engine using a detector meeting the requirements of Special Condition 29. The sample ports and the collection system must be designed and operated such that there is no air leakage into the sample probe or the collection system downstream of the engine. The concentrations shall be recorded and the MSS activity shall be stopped as soon as possible if the VOC concentration exceeds 100 ppmv above background.

E. The plant flare system

(1) The heating value and velocity requirements in 40 CFR 60.18 shall be satisfied during operations authorized by this permit.

(2) The flare shall be operated with a flame present at all times and/or have a constant pilot flame. The pilot flame shall be continuously monitored by a thermal couple or an infrared monitor. The time, date, and duration of any loss of pilot flame shall be recorded. Each monitoring device shall be accurate to, and shall be calibrated at a frequency in accordance with, the manufacturer's specifications or equivalent.

(3) Monitoring shall be used to maintain waste gas above the minimum heating value. Measurement, good engineering practice, or process

knowledge shall be used to maintain waste gas above the minimum heating.

(4) The combined assist natural gas and waste gas stream shall meet Title 40 CFR § 60.18 specifications of minimum heating value and maximum tip velocity. All flares shall have a continuous flow monitor that provides a record of the vent stream to the flare at least 95% of the time the flare is operational, averaged over a calendar year.

F. A Closed Loop Refrigerated Vapor Recovery System.

(1) The vapor recovery system shall be installed on the facility to be degassed using good engineering practice to ensure air contaminants are flushed from the facility through the refrigerated vapor condensers and back to the facility being degassed. The vapor recovery system and facility being degassed shall be enclosed except as necessary to ensure structural integrity (such as roof vents on a floating roof tank).

(2) VOC concentration in vapor being circulated by the system shall be sampled and recorded at least once every 4 hours at the inlet of the condenser unit with an instrument meeting the requirements of Special Condition 29.

(3) The quantity of liquid recovered from the tank vapors and the tank pressure shall be monitored and recorded each hour. The liquid recovered shall increase with each reading and the tank pressure shall not exceed one inch water pressure while the system is operating.

38. The following requirements apply to capture systems for the plant flare system. **(03/11)**

A. Either conduct a once a month visual, audible, and/or olfactory inspection of the capture system to verify there are no leaking components in the capture system; or verify the capture system is leak-free by inspecting in accordance with 40 CFR Part 60, Appendix A, Test Method 21 once a year. Leaks shall be indicated by an instrument reading greater than or equal to 500 ppmv above background.

B. The control device shall not have a bypass.

or

If there is a bypass for the control device, comply with either of the following requirements:

(1) Install a flow indicator that records and verifies zero flow at least once every fifteen minutes immediately downstream of each valve that if opened would allow a vent stream to bypass the control device and be emitted, either directly or indirectly, to the atmosphere; or

(2) Once a month, inspect the valves, verifying the position of the valves and the condition of the car seals that prevent flow out the bypass.

A bypass does not include authorized analyzer vents, highpoint bleeder vents, low point drains, or rupture discs upstream of pressure relief valves if the pressure between the disc and relief valve is monitored and recorded at least weekly. A deviation shall be reported if the monitoring or inspections indicate bypass of the control device when it is required to be in service per this permit.

C. If any of the above inspections is not satisfactory, the permit holder shall promptly take necessary corrective action. Records shall be maintained documenting the performance and results of the inspections required above.

39. If spray guns are used to apply paint, they shall be airless, high volume low pressure (HVLP), or have the same or higher transfer efficiency as airless or HVLP spray guns. **(03/11)**

40. Emissions from all painting activities, except for minor painting identified in Attachment A to this permit, at this site must satisfy the criteria below. New compounds may also be added through the use of the procedure below. **(03/11)**

A. Short-term (pounds per hour [lb/hr]) and annual (TPY) emissions shall be determined for each chemical in the paint as documented in the permit application. The calculated emission rate shall not exceed the maximum allowable emissions rate at any emission point.

B. The Effect Screening Level (ESL) for the material shall be obtained from the current TCEQ ESL list or by written request to the TCEQ Toxicology Section.

C. The total painting emissions of any compound must satisfy one of the following conditions:

(1) The total emission rate is less than 0.1 lb/hr and the ESL greater than or equal to 2 μg/m3; or

(2) The emission rate of the compound in pounds per hour is less than the ESL for the compound divided by 1000 (ER<ESL/1000).

D. The permit holder shall maintain records of the information below and the demonstrations in steps A though C above. The following documentation is required for each compound:

(1) Chemical name(s), composition, and chemical abstract registry number if available.

(2) Material Safety Data Sheet.

(3) Maximum concentration of the chemical in weight percent

(4) Paint usage and the associated emissions shall be recorded each month and the rolling 12 month total emissions updated.

41. No visible emissions shall leave the property due to painting or abrasive blasting. **(03/11)**

42. Black Beauty and Garnet Sand may be used for abrasive blasting. The permit holder may also use blast media that meet the criteria below: **(03/11)**

A. The media shall not contain asbestos or greater than 1.0 weight percent crystalline silica.

B. The weight fraction of any metal in the blast media with a short term effects screening level (ESL) less than 50 micrograms per cubic meter as identified in the most recently published TCEQ ESL list shall not exceed the ESLmetal/1000.

C. The MSDS for each media used shall be maintained on site.

Blasting media usage and the associated emissions shall be recorded each month.

43. With the exception of the interim MAERT emission limits, these permit conditions become effective on the first day of the month following 180 days after this permit has been issued. During this period, emissions shall be estimated using good engineering practice and methods to provide reasonably accurate representations for emissions. The basis used for determining the quantity of air contaminants to be emitted shall be recorded. The permit holder may maintain abbreviated records of emissions from Attachment A and B activities as allowed in Special Condition 26 rather than documenting all the information required by Special Condition 26.A. through D. **(03/11)**

44. Planned MSS activities must be conducted in a manner consistent with good practice for minimizing emissions, including the use of air pollution control equipment, practices, and processes. All reasonable and practical efforts to comply with Special Conditions 1, and 26 through 44, must be used when conducting the planned MSS activity, until the commission determines that the efforts are unreasonable or impractical, or that the activity is an unplanned MSS activity. **(03/11)**

Dated: July 7, 2014

Permit 3452

Attachment A - Inherently Low Emitting Activities

Activity (See BOP MSS permit application for further definition of each category)	VOC	NOx	CO	PM	SO_2	H_2SO_4	NH_3
Inspection, repair, replacement, and maintenance on analytical equipment	x	x	x	x	x	x	x
Inspection, repair, replacement, adjustment, testing, calibration, and maintenance of Instrumentation/analyzer	x	x	x	x	x	x	x
Aerosol Cans and other consumables	x		x	x			
Management of sludge from puts, ponds, sumps, and water conveyances	x			x	x	x	x
Inspection, repair, and replacement of Carbon Canisters	x		x		x	x	
Catalyst charging/handling	x			x	x	x	x
Meter proving	x	x	x		x	x	x
Inspection, repair, and replacement of filters and screens	x		x	x	x	x	x
Soap and other liquid based cleaners	x				x	x	x
Inspection, repair, and replacement of monitoring/measuring equipment (e.g., sight glasses, rotometers)	x	x	x		x	x	X
Cleaning (including strainers, lube oil systems)	x		x	x	x	x	x
Leak and operability checks (e.g., steam turbine overspeed tests, troubleshooting)	x	x	x	x	x	x	x
Inspection, repair, and replacement of water treatment systems (cooling, boiler, potable)	x						x
Combinations of the above	x	x	x	x	x	x	x

Dated: July 14, 2011

Permit 3452

Attachment B

Pump, compressor, vessel, exchanger, furnace, boiler inspection repair/replacement, or combination of the preceding not included in attachment A.

Catalyst activation and deactivation.

Inspection, repair, and replacement of fugitive components where process fluid is not vented to the atmosphere (e.g., control valve stem lubrication, filter, gasket replacement, use of pipe thread sealant).

Inspection, repair, and replacement of fugitive components where a process fluid is vented to the atmosphere.

Inspection, repair, and replacement of pipe and ancillary equipment (eg coupling alignment, oil seals, blindings).

Welding

Dated: July 14, 2011

Permit 3452

Attachment C - MSS Activity Summary

Facilities	Description	Emissions Activity	EPN
See Attachment A	inherently low emitting activities	see attachment A	MAINANALYZ MAININSTR MAINPIPE MAINPUMP MAINVALVE MAINVESS MAINBOIL MAINEXCH MAINCOMP MAINFURN CONSUMABLE
See Attachment B	routine maintenance activities	see attachment B	MAINPUMP MAINVALVE MAINPIPE MAINCOMP MAINEXCH MAINVESS MAINANALYZ MAINBOIL MAINFURN MAININSTR
All Storage Tanks	storage tank draining/degassing/ cleaning/repair/refilling	de-inventory, degassing, tank cleaning, repair, refilling, and intervening maintenance	FLARE1/2/X MAINTANKTO ICENGINES TANKMSS
All Floating Roof Tanks	tank roof landing	empting with landed roof	FLARE1/2/X MAINTANKTO ICENGINES TANKMSS MAINTANKTO

Facilities	Description	Emissions Activity	EPN
All Floating Roof Tanks	degas of tank with landed roof	controlled degassing	FLARE1/2/X MAINTANKTO ICENGINES TANKMSS MAINTANKTO
All Production Related Equipment	vacuum truck loading	remove contents prior to degassing, washing, maintenance, change of service, collecting materials accumulated in waste/wastewater equipment	VACTRUCKMSS
All production related equipment	process unit shutdown/depressurize/drain	vent to flare	FLARE1/2/X
All production related equipment	production related equipment purge/degas/drain	vent to atmosphere	ATM
All production related equipment	process unit startup	vent to flare	FLARE1/2/X
All production related equipment	preparation for facility/component repair/replacement	vent to flare	FLARE1/2/X
All production related equipment	preparation for facility/component repair/replacement	vent to atmosphere	ATM
All production related equipment	recovery from facility/component repair/replacement	vent to flare/thermal oxidizer	FLARE1/2/X MAINTANKTO
All production related equipment	recovery from facility/component repair/replacement	vent to atmosphere	ATM
All production related equipment	preparation for unit turnaround or facility/component repair/replacement	remove liquid/ vent to flare/thermal oxidizer, or atmosphere	FLARE1/2/X MAINTANKTO ATM VACTRUCKMSS ICENGINE

Facilities	Description	Emissions Activity	EPN
Frac Tanks and Temporary Liquid Storage	small portable tanks used for maintenance, startup, shutdown or normal operations including tank and process unit cleaning operations	working and standing losses from frac tanks and temporary liquid storage	FRACTMSS
All Production-Related Equipment	Abrasive Blasting	PM from blasting media	ABRASBLAST
All Production-Related Equipment	Non-VOC coating	thermal spray aluminum	TSAMSS
All Production Related Equipment	combustion unit startup	vent to a flares	FLARE1/2/X COMBUSTSU
All Production-Related Equipment	periodic flaring	vent to flares	FLARE1/2/X
All Production-Related Equipment	combination of above	combination of above	combination of above

Dated: July 14, 2011

Emission Sources - Maximum Allowable Emission Rates

Flexible Permit Numbers 3452, PSDTX302M2 and PAL6

This table lists the maximum allowable emission rates and all sources of air contaminants on the applicant's property covered by this permit. The emission rates shown are those derived from information submitted as part of the application for permit and are the maximum rates allowed for these facilities, sources, and related activities. Any proposed increase in emission rates may require an application for a modification of the facilities covered by this permit.

Air Contaminants Data

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
NO_x Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
FLARE1	Primary Flare			
FLARE2	Secondary Flare			
FLAREX	Expansion Flare			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
XZL16	Emergency Generator			
ICSTG01	Train 1 Diesel Starter Engine			
ICSTG02	Train 2 Diesel Starter Engine			
ICSTG03	Train 3 Diesel Starter Engine			
ZP11DSL1	Diesel Pump			
ZP11DSL2	Diesel Pump			
COMBUSTSU	Combustion Unit			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Periodic Flaring			
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
Final Flex Emission Cap		NO_x	1630.75	2448.71
Final MSS Emission Cap		NO_x (7)	143.79	401.8
VOC Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
FLARE1	Primary Flare			
FLARE2	Secondary Flare			
FLAREX	Expansion Flare			
ZP11DSL1	Diesel Pump			
ZP11DSL2	Diesel Pump			
BOPCT	Cooling Tower (5)			
ICSTG01	Train 1 Diesel Starter Engine			
ICSTG02	Train 2 Diesel Starter Engine			
ICSTG03	Train 3 Diesel Starter Engine			
XZL16	Emergency Generator			
CSS	Storm Sewer			
BOPXCT	Cooling Tower (5)			
BOPFUG	Fugitives (5)			
ND08	ND-08 Vent			
TTAILS	Safety Relief Valves			
ANALYZ	Analyzer Vents			
RD16	RD-16 Vent			
PROCSEWR	Process Sewer			
LC01-VE	Compressor Drain Vents			
LC01-RES	Compressor Drain Vents			
VC01-VE	Compressor Drain Vents			
VC01-RES	Compressor Drain Vents			
PC01-VE	Compressor Drain Vents			
PC01-RES	Compressor Drain Vents			
WWTBIOX	Biological Oxidation			
LABVENT	Lab Vent			
PAINTING	Painting			
ZTK05	Feed Tank ZTK-05			
ZTK06	Feed Tank ZTK-06			
ZTK07	Feed Tank ZTK-07			
ZTK08	Feed Tank ZTK-08			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
ZTK09A	Steam Cracked Tar Tank ZTK-09A			
ZTK09B	Steam Cracked Tar Tank ZTK-09B			
ZTK10	Feed Tank ZTK-10			
ZTK11	Quench Oil Tank ZTK-11			
ZTK12A	Slop Oil Tank ZTK-12A			
ZTK12B	Slop Oil Tank ZTK-12B			
ZTK13	Spent Caustic Tank ZTK13			
MD20	Inhibitor Tank MD-20			
MTK01	Methanol/Propanol Tank MTK-01			
UTK01	Gas Oil Inhibitor Tank UTK-01			
UTK102A	Tank UTK-102A			
UTK102B	Tank UTK-102B			
XZLTK16	Diesel Fuel Tank			
XZTK05	WW Equalization Tank			
XZTK06	Spent Caustic Tank			
XZTK07	Pyrolysis Fuel Oil Tank			
XZTK11	Wash Oil Tank			
XZMIS01	Oil Mist Tank			
XZMIS02	Oil Mist Tank			
XZMIS03	Oil Mist Tank			
XZMIS04	Oil Mist Tank			
ZLTK01	Tank ZLTK-01A			
ZTK25	Tank ZTK25			
ZTK28	Tank ZTK28			
PIPEFUG	Piping Fugitives (5)			
COMBUSTSU	Combustion Startup			
CONSUMABLE	Consumables			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Periodic Flaring			
FRACTMSS	Frac Tanks			
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAININSTR	Maintenance Instruments			
MAINFURN	Maintenance Furnaces			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
TANKMSS	Storage Tank Maintenance			
TSAMSS	Thermal Spray Aluminum			
VACTRKMSS	Vacuum Trucks			
Final Flex Emission Cap		VOC	709.48	435.77

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
Final MSS Emission Cap		VOC (7)	416.1	42.04
CO Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
CAF01-DEC	Decoking Stack AF-01			
CBF01-DEC	Decoking Stack BF-01			
CCF01-DEC	Decoking Stack CF-01			
CDF01-DEC	Decoking Stack DF-01			
CEF01-DEC	Decoking Stack EF-01			
CFF01-DEC	Decoking Stack FF-01			
CGF01-DEC	Decoking Stack GF-01			
CHF01-DEC	Decoking Stack HF-01			
CIF01-DEC	Decoking Stack IF-01			
CJF01-DEC	Decoking Stack JF-01			
COF01-DEC	Decoking Stack OF-01			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
CQF01-DEC	Decoking Stack QF-01			
XAF01-DEC	Decoking Stack XAF-01			
XBF01-DEC	Decoking Stack XBF-01			
XCF01-DEC	Decoking Stack XCF-01			
XDF01-DEC	Decoking Stack XDF-01			
XEF01-DEC	Decoking Stack XEF-01			
XFF01-DEC	Decoking Stack XFF-01			
XGF01-DEC	Decoking Stack XGF-01			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
FLARE1	Primary Flare			
FLARE2	Secondary Flare			
FLAREX	Expansion Flare			
XZL16	Emergency Generator			
BOPFUG	Fugitives (5)			
ND08	ND-08 Vent			
ICSTG01	Train 1 Diesel Starter Engine			
ICSTG02	Train 2 Diesel Starter Engine			
ICSTG03	Train 3 Diesel Starter Engine			
ZP11DSL1	Diesel Pump			
ZP11DSL2	Diesel Pump			
COMBUSTSU	Combustion Startup			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Periodic Flaring			
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINVALVE	Maintenance Valve			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVESS	Maintenance Vessels			
Final Flex Emission Cap		CO	6627.58	2381.15
Final MSS Emission Cap		CO (7)	483.99	388.25

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
PM Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
CAF01-DEC	Decoking Stack AF-01			
CBF01-DEC	Decoking Stack BF-01			
CCF01-DEC	Decoking Stack CF-01			
CDF01-DEC	Decoking Stack DF-01			
CEF01-DEC	Decoking Stack EF-01			
CFF01-DEC	Decoking Stack FF-01			
CGF01-DEC	Decoking Stack GF-01			
CHF01-DEC	Decoking Stack HF-01			
CIF01-DEC	Decoking Stack IF-01			
CJF01-DEC	Decoking Stack JF-01			
COF01-DEC	Decoking Stack OF-01			
CQF01-DEC	Decoking Stack QF-01			
XAF01-DEC	Decoking Stack XAF-01			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
XBF01-DEC	Decoking Stack XBF-01			
XCF01-DEC	Decoking Stack XCF-01			
XDF01-DEC	Decoking Stack XDF-01			
XEF01-DEC	Decoking Stack XEF-01			
XFF01-DEC	Decoking Stack XFF-01			
XGF01-DEC	Decoking Stack XGF-01			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
XZL16	Emergency Generator			
LUBE1	Gas Turbine Lube Oil Vent			
ICSTG01	Train 1 Diesel Starter Engine			
ICSTG02	Train 2 Diesel Starter Engine			
ICSTG03	Train 3 Diesel Starter Engine			
ZP11DSL1	Diesel Pump			
ZP11DSL2	Diesel Pump			
ABRASBLAST	Dry Abrasive Blasting			
COMBUSTSU	Combustion Startup			
EQPERIODIC	Period Equipment Leaks			
FLPERIODIC	Period Flaring			
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
TANKMSS	Storage Tank Maintenance			
TSAMSS	Thermal Spray Aluminum			
Final Flex Emission Cap		PM	337.49	365.62
Final MSS Emission Cap		PM (7)	16.77	14.61

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
SO_2 Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
FLARE1	Primary Flare			
FLARE2	Secondary Flare			
FLAREX	Expansion Flare			
XZL16	Emergency Generator			
ICSTG01	Train 1 Diesel Starter Engine			
ICSTG02	Train 2 Diesel Starter Engine			
ICSTG03	Train 3 Diesel Starter Engine			
COMBUSTSU	Combustion Startup			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Periodic Flaring			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
Final Flex Emission Cap		SO_2	441.28	182.79
Final MSS Emission Cap (7)		SO_2 (7)	30.34	40.74

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
NH_3 Sources				
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG5	164 MW Gas Turbine			
PIPEFUG	Piping Fugitives (5)			
XGF-01-ST	Furnace XGF-01			
NH3LOAD	Ammonia Loading			
ZP11DSL1	Diesel Pump			
ZP11DSL2	Diesel Pump			
FRACTMSS	Frac Tanks			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Period Flaring			
INPERIODIC	Period Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINTANKTO	Combustion Control Device			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
TANKMSS	Storage Tank Maintenance			
Final Flex Emission Cap		NH_3	51.8	196.24
Final MSS Emission Cap		NH_3 (7)	16.67	0.29
H_2SO_4 Sources				
CAF01-ST	Furnace AF-01			
CBF01-ST	Furnace BF-01			
CCF01-ST	Furnace CF-01			
CDF01-ST	Furnace DF-01			
CEF01-ST	Furnace EF-01			
CFF01-ST	Furnace FF-01			
CGF01-ST	Furnace GF-01			
CHF01-ST	Furnace HF-01			
CIF01-ST	Furnace IF-01			
CJF01-ST	Furnace JF-01			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
COF01-ST	Furnace OF-01			
CQF01-ST	Furnace QF-01			
XAF01-ST	Furnace XAF-01			
XBF01-ST	Furnace XBF-01			
XCF01-ST	Furnace XCF-01			
XDF01-ST	Furnace XDF-01			
XEF01-ST	Furnace XEF-01			
XFF01-ST	Furnace XFF-01			
XGF01-ST	Furnace XGF-01			
E-7-1	Boiler A			
E-7-1	Boiler B			
E-7-1	Boiler C			
E-7-1	Boiler D			
HRSG1	39 MW Gas Turbine			
HRSG2	39 MW Gas Turbine			
HRSG3	39 MW Gas Turbine			
HRSG4	95.5 MW Gas Turbine			
HRSG1	Steam Generator			
HRSG2	Steam Generator			
HRSG3	Steam Generator			
HRSG4	Steam Generator			
HRSG5	164 MW Gas Turbine			
DIESEL1A	Diesel Engine			
DIESEL4	Diesel Engine			
DIESELFW	Diesel Engine			
XZL16	Emergency Generator			
FLARE1	Primary Flare			
FLARE2	Secondary Flare			
FLAREX	Expansion Flare			
COMBUSTSU	Combustion Startup			
EQPERIODIC	Periodic Equipment Leaks			
FLPERIODIC	Periodic Flaring			
FRACTMSS	Frac Tanks			
INPERIODIC	Periodic Instrument Failure			
MAINANALYZ	Maintenance Analyzers			
MAINBOIL	Maintenance Boilers			
MAINCOMP	Maintenance Compressors			
MAINEXCH	Maintenance Exchangers			
MAINFURN	Maintenance Furnaces			
MAININSTR	Maintenance Instruments			
MAINPIPE	Maintenance Pipe			
MAINPUMP	Maintenance Pumps			
MAINVALVE	Maintenance Valve			
MAINVESS	Maintenance Vessels			
TANKMSS	Storage Tank Maintenance			
VACTRKMSS	Vacuum Truck			

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
Final Flex Emission Cap		H_2SO_4	34.21	17.94
MSS Emission Cap		H_2SO_4 (7)	6.66	3.4
Maintenance, Start-Up, and Shutdown (MSS) Limits Case I - Duct Burners Unfired (6)				
HRSG1	39 MW Gas Turbine	NO_x	364	---
		CO	688.73	---
		VOC	1	---
		PM	2.63	---
		SO_2	1.9	---
		NH_3	14.23	---
HRSG2	39 MW Gas Turbine	NO_x	364	---
		CO	688.73	---
		VOC	1	---
		PM	2.63	---
		SO_2	1.9	---
		NH_3	14.23	---
HRSG3	39 MW Gas Turbine	NO_x	364	---
		CO	688.73	---
		VOC	1	---
		PM	2.63	---
		SO_2	1.9	---
		NH_3	14.23	---

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
HRSG4	95.5 MW Gas Turbine	NO_x	980	---
		CO	1855.56	---
		VOC	3.26	---
		PM	5	---
		SO_2	2.15	---
HRSG5	164 MW Gas Turbine	NO_x	1080.12	---
		CO	2723.51	---
		VOC	24.61	---
		PM	26.14	---
		SO_2	18.00	---
		NH_3	26.61	---
		H_2SO_4	2.11	---
Maintenance, Start-Up, and Shutdown (MSS) Limits Case 2- Duct Burners Fired (6)				
HRSG1	39 MW Gas Turbine	NO_x	396.9	---
		CO	716.59	---
		VOC	4.06	---
		PM	5.29	---
		SO_2	7.3	---
		NH_3	20.48	---

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	**Source Name (2)**	**Air Contaminant Name (3)**	**Emission Rates**	
			lbs/hour	**TPY (4)**
HRSG5	164 MW Gas Turbine	NO_x	1080.12	---
		CO	2723.51	---
		VOC	24.61	---
		PM	26.14	---
		SO_2	18.00	---
		NH_3	26.61	---
		H_2SO_4	2.11	---
Plantwide Applicability Limits (PAL) (8)				
NO_x PAL		NO_x	---	2448.71
VOC PAL		VOC	---	435.77
CO PAL		CO	---	2381.15
PM PAL		PM	---	463.55
SO_2 PAL		SO_2	---	182.79
H_2SO_4 PAL		H_2SO_4	---	17.94

(1) Emission point identification - either specific equipment designation or emission point number from plot plan.
(2) Specific point source names. For fugitive sources use area name or fugitive source name.
(3) NO_x - total oxides of nitrogen
CO - carbon monoxide
VOC - volatile organic compounds as defined in Title 30 Texas Administrative Code § 101.1
PM - total particulate matter, suspended in the atmosphere, including PM_{10} and $PM_{2.5}$, as represented
PM_{10} - total particulate matter equal to or less than 10 microns in diameter, including $PM_{2.5}$, as represented
$PM_{2.5}$ - particulate matter equal to or less than 2.5 microns in diameter
SO_2 - sulfur dioxide
NH_3 - ammonia
H_2SO_4 - sulfuric acid mist
(4) Compliance with annual emission limits (tons per year) is based on a 12 month rolling period.
(5) Fugitive emissions are an estimate only and should not be considered as a maximum allowable emission rate.

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
HRSG2	39 MW Gas Turbine	NO_x	396.9	---
		CO	716.59	---
		VOC	4.06	---
		PM	5.29	---
		SO_2	7.3	---
		NH_3	20.48	---
HRSG3	39 MW Gas Turbine	NO_x	396.9	---
		CO	716.59	---
		VOC	4.06	---
		PM	5.29	---
		SO_2	7.3	---
		NH_3	20.48	---
HRSG4	95.5 MW Gas Turbine	NO_x	1026	---
		CO	1893.1	---
		VOC	8.26	---
		PM	8.1	---
		SO_2	11.15	---

Emission Sources - Maximum Allowable Emission Rates

(6) Case 1 and Case 2, maintenance, startup, and shutdown (MSS) conditions are applicable for a maximum of twelve hours at any one time. For any occurrence of MSS conditions described in Case 1 or Case 2 lasting more than twelve hours, notification shall be made to the Houston Regional Office of the Texas Commission on Environmental Quality.
(7) Planned maintenance, startup, and shutdown (MSS) activities described in the permit special conditions.
(8) PAL6 application for renewal must be submitted no later than six months before August 24, 2015.

Date: July 7, 2014

Attachment 3

- EPA Statement of Basis for Permit PSD-TX-102982-GHG

Statement of Basis
Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for the ExxonMobil Chemical Company, Baytown Olefins Plant

Permit Number: PSD-TX-102982-GHG

May 2013

This document serves as the statement of basis for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On May 22, 2012, the ExxonMobil Chemical Company (ExxonMobil) Baytown Olefins Plant (BOP) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions for a proposed construction project at an existing major stationary source of criteria pollutants. In connection with the same proposed project, ExxonMobil submitted a minor NSR permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 22, 2012. The project at the Baytown Olefins Plant proposes to construct a new ethylene production unit consisting of eight ethylene cracking furnaces and recovery equipment to produce polymer grade ethylene. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the ExxonMobil, Baytown Olefins Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that ExxonMobil's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information requested by EPA and provided by ExxonMobil, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

ExxonMobil Chemical Company
Baytown Olefins Plant
P.O. Box 4004
Baytown, TX 77522-4004

Physical Address:
3525 Decker Drive
Baytown, TX 77522

Contact:
Benjamin Hurst
Air Permit Advisor
ExxonMobil Chemical Company
(281) 834-6110

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305).

The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

IV. Facility Location

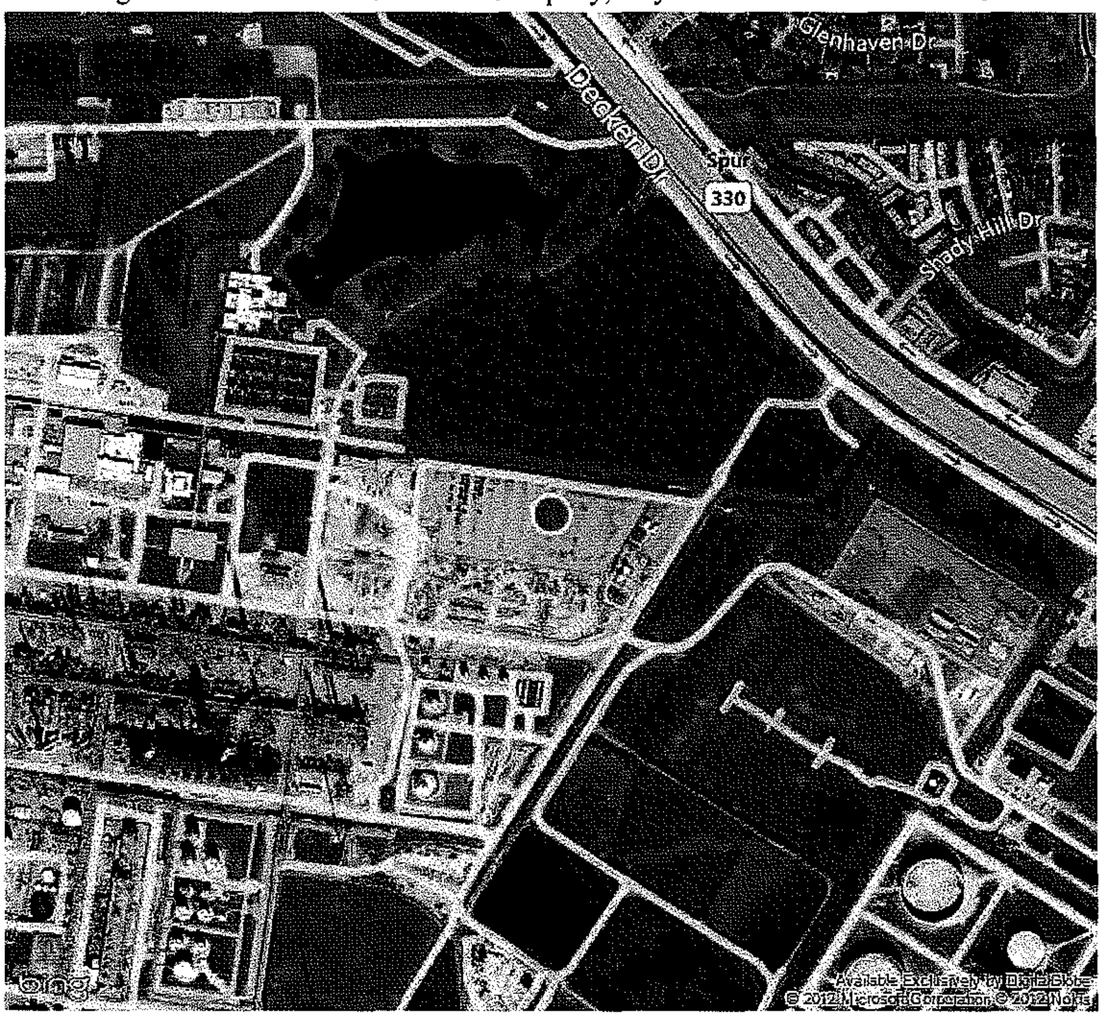
The ExxonMobil, Baytown Olefins Plant is located in Harris County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29° 49' 29.58" North
Longitude: - 95° 0'24.22" West

Harris County is currently designated severe nonattainment for ozone, and is currently designated attainment for all other pollutants. The nearest Class I area, at a distance of more than 500 kilometers, is Caney Creek Wilderness Area.

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. ExxonMobil Chemical Company, Baytown Olefins Plant Location



V. Applicability of Prevention of Significant Deterioration (PSD) Regulations

EPA concludes ExxonMobil's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility in excess of the emission thresholds described at 40 CFR § 52.21(b)(49)(v). The facility is an existing major stationary source (as well as a source with a PTE that equals or exceeds 100,000 TPY CO2e and 100/250TPY GHGs mass basis), and the planned modification has a GHG emissions increase that equals or exceeds 75,000 TPY CO2e (and 0 TPY GHGs mass basis). ExxonMobil calculated a CO_2e emissions increase of 1,479,665 tpy for the proposed project.

EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305. EPA Region 6 considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases." As recommended in that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with BACT is the best technique that can be employed at present to satisfy additional impacts analysis and Class I area requirements of the rules as they relate to GHGs. The applicant submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project. EPA's PSD permitting action will only authorize emissions of GHGs.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ExxonMobil to construct a new ethylene production unit consisting of eight new steam cracking furnaces and recovery equipment at the existing olefins plant at the Baytown Olefins Plant (BOP) located in Baytown, Harris County, Texas. The major pieces of recovery equipment include a quench tower, caustic wash facilities, a process gas compressor and interstage coolers, a chiller train, a refrigeration system, a deethanizer, an ethylene/ethane (C_2) splitter, and a demethanizer. Bottoms product from the new deethanizer will serve as feed to the existing base plant depropanizer. In addition, a new cooling tower and a new flare system will be constructed. Existing utilities (such as plant air, electric, marginal steam product) will support the proposed project as needed. The modification increases the plant capacity, adding approximately 2 million metric tons per year of ethylene produced. The site will also have an increase in other products, including fuel gas, propylene, a heavy components (C3+) stream, and other lower-output hydrocarbon streams.

The ethylene production unit will operate by firing the furnace section, consisting of eight steam cracking furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST) continuously. The furnace design is proprietary and is equipped with ultra low NOx burners and Selective Catalytic Reduction (SCR) systems to control NOx emissions. The furnaces will crack fresh ethane that is combined with recycled ethane. Steam is introduced as part of the process. The furnace outlet stream is cooled in the Quench Tower.

A steam-educted stream from the wet air oxidation unit, along with various other streams (process off gas) with a low hydrocarbon concentration, will be routed to the steam cracking furnaces for safety and/or to provide for control of volatile organic compounds (VOC). The process off gas stream is composed of mainly steam, nitrogen, and a small amount of hydrocarbons. The streams routed to the fire boxes of the proposed cracking furnaces are expected to account for less than 0.4% of the carbon entering the furnaces on an annual basis, and will contribute less than 0.01% to the annual GHG mass basis tpy emissions.

The furnaces will fire imported natural gas or a blended fuel gas that consists of imported natural gas and tail gas. The tail gas is a recycle stream resulting from an initial separation of methane and hydrogen during the chilling step within the demethanizer system. The composition of blended fuel gas will vary and will depend on current hydrogen production and disposition.

In the cracking operation, coke (molecular carbon) gradually builds on the inside walls of the furnace tubes. This layer of coke impedes heat transfer and must be removed while the furnace is offline through a steam/air decoke operation, which is expected to occur approximately every 30 days. The coke is removed from the walls of the furnace tubes through oxidation and spalling. The spalled coke fines are disengaged from the furnace effluent in the decoke drum. Particulate matter emissions are controlled through cyclonic separators at the decoke drum vent which releases to atmosphere (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC).

The combined furnace effluent will flow into the Quench Tower where it is cooled with quench water. The majority of the dilution steam and some of the heavier hydrocarbons are condensed and exit the tower bottoms.

The deethanizer will separate the hydrocarbons with two or less carbon atoms from heavier hydrocarbons. The overhead stream from this process will be sent to the Acetylene Converters where acetylene is converted to ethylene and ethane. The Deethanizer bottoms product, hydrocarbons with more than 2 carbon atoms, is sent to the Depropanizer in the existing plant facilities.

A new cooling tower (EPN: BOPXXCT) will be constructed to provide process heat removal and supply cooling water to the proposed project. This cooling tower will be a multi-cell, induced draft, counter-flow type cooling tower. No GHG emissions will be emitted by the cooling tower.

A new flare system (EPNs: FLAREXX1 and FLAREXX2) will be designed to provide safe control of gases vented from the proposed project. This system will be equipped with a totalizing flow meter and an on-line analyzer to speciate the hydrocarbons in the flare gases, including Highly Reactive Volatile Organic Compounds (HRVOCs).

The proposed project includes up to five backup generators, total power output will not exceed three megawatts total. Each unit is powered by a diesel engine (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, and DIESELXX05) and there will be one diesel storage tank associated with each backup generator installed. The normal operation of the generators is to test for proper operation weekly.

The proposed project will provide two booster pumps for the existing firewater system. These pumps will each be powered by a diesel engine (EPNs: DIESELXXFW1 and DIESELXXFW2). The normal operation of the booster pumps and engines is to test for proper operation weekly.

Duct burners will be added to the existing heat recovery steam generator (HRSG) section of the gas turbine generator train 5 (Train 5) to provide supplemental heat to the turbine exhaust stream, thereby generating supplemental steam for use at the Baytown Olefins Plant. Train 5 (HRSG05) is located at the Baytown Olefins Plant's base plant and is equipped with a Selective Catalytic Reduction (SCR) unit for NOx emission control. The HRSG section's function is to generate steam by recovering heat contained in the exhaust gas stream of the gas turbine generator. The purpose of the duct burners is to generate incremental steam during times when the steam cracking furnaces are unable to meet the steam demand. The duct burners are configured in rows and will be fired at their design firing rate to create additional steam from natural gas firing. There will be no increase in the firing of the gas turbine generator section of Train 5 due to the installation of the duct burners.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit considered the recommendations in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a "top-down" BACT analysis. Those steps are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., cracking furnaces, furnace decoking, duct burners flare, and emergency engine testing). The site has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. These stationary combustion sources primarily emit carbon dioxide (CO_2), and small amounts of nitrous oxide (N_2O) and methane (CH_4). The following devices are subject to this GHG PSD permit:

- Steam Cracking Furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST)
- Decoke Drum Vents (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC)
- Train 5 Duct Burners (EPN: HRSG05)
- Flare System (EPNs: FLAREXX1 and FLAREXX2)
- Engines (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, DIESELXX05, DIESELXXFW1, and DIESELXXFW2)
- Equipment Fugitives (EPN: BOPXXAREA)

IX. Steam Cracking Furnaces (EPNs: XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST)

The ethylene unit consists of eight proprietary steam cracking furnaces (XXAF01-ST, XXBF01-ST, XXCF01-ST, XXDF01-ST, XXEF01-ST, XXFF01-ST, XXGF01-ST, and XXHF01-ST). The furnaces are equipped with low NOx burners and selective catalytic reduction (SCR) systems to control NOx emissions. Furnace fuel is natural gas or a blended fuel gas that consists of natural gas and tail gas from the demethanizer system.

Various streams with very low hydrocarbon concentrations will be routed to the steam cracking furnaces for safety and/or to provide control of volatile organic compounds (VOC). The streams routed to the fireboxes of the steam cracking furnaces are expected to account for less than 0.4% of the carbon entering the furnaces on an annual basis, and will contribute less than 0.01% to the annual GHG mass basis tpy emissions. These streams are not considered a fuel source for the cracking furnaces. These are two phase streams that do not lend themselves to accurate measurements via on-line flow meters, analyzers, or even grab samples. The emissions from the control of these vent streams will be estimated using company records as defined in 40 CFR § 98.6, and the high heating value (HHV) and emission factors will be taken from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Equations C-1 and C-8 as defined in 40 CFR Subpart C will be used for the calculation. These emissions are included in the total GHG mass emissions from the cracking furnaces.

As part of the PSD review, ExxonMobil provides in the GHG permit application a 5-step top-down BACT analysis for the eight steam cracking furnaces. EPA has reviewed ExxonMobil's BACT analysis for the furnaces, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit, as summarized below.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Energy Efficient Design* – ExxonMobil selected an energy efficient proprietary design for its steam cracking furnaces. To maximize thermal efficiency at BOP, the steam cracking furnaces will be equipped with heat recovery systems to produce steam from waste heat for use throughout the plant.
- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. ExxonMobil proposes to use natural gas or a blended fuel gas that consists of natural gas and tail gas.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

Carbon Capture and Sequestration (CCS)

Carbon capture and sequestration is a GHG control process that can be used by "facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)."[1] CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). Accordingly, pre-combustion capture and oxyfuel combustion are

[1]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)

not considered available control options for this proposed facility; the third approach, post-combustion capture, is applicable to the steam cracking furnaces.
Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[3]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Fuel (approximately 40%)
- Energy Efficient Design
- Good Operating and Maintenance Practices

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the most effective control method. CCS is technically feasible. Use of low-carbon fuel, energy efficient design, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. These technologies all may be used concurrently (including, at least in theory, in conjunction with CCS). The estimated efficiencies were obtained from Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as efficiencies associated with new equipment.

[2] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

[3] Based on the information provided by ExxonMobil and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology is technologically feasible at this source.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Carbon Capture and Sequestration

ExxonMobil developed a cost analysis for CCS that provided the basis for eliminating the technology in step 4 of the BACT process as a viable control option based on economic costs. The majority of the cost for CCS was attributed to the capture and compression facilities that would be required. The total annual cost of CCS capital and operating expenses would be $205,000,000 per year, including the cost of transport. The addition of CCS would increase the total capital project costs by more than 25%. EPA Region 6 reviewed ExxonMobil's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project. Thus, CCS has been eliminated as BACT for this project.

Economic infeasibility notwithstanding, ExxonMobil also asserts that CCS can be eliminated as BACT based on the energy and environmental impacts from a collateral increase of criteria pollutants (i.e. those pollutants for which EPA has promulgated primary and secondary National Ambient Air Quality Standards). Implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, and SO_2 by as much as 11% from the additional utilities and energy consumption demands that would be required to operate the CCS system. The increase in criteria pollutants would be greater if looking at the emissions from the other support equipment that would be needed to further treat and compress the CO_2 emissions sufficiently to transport it to an appropriate sequestration location. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area.

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Use of blended fuel gas, because of its rich hydrogen content (average of 74 mol%), contains less carbon than natural gas.

Energy Efficient Design

The use of an energy efficient furnace and unit design is economically and environmentally practicable for the proposed project. By optimizing energy efficiency, the project requires less fuel than comparable less-efficient operations, resulting in cost savings. Further, reduction in fuel consumption corresponding to energy efficient design reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well. Specific technologies utilized by the furnaces include the following:

- Economizer - Use of heat exchanger to recover heat from the exhaust gas to preheat incoming Steam Drum feedwater to attain thermal efficiency.
- Steam Generation from Process Waste Heat - Use of heat exchangers to recover heat from the process effluent to generate high pressure steam. The high pressure steam is then superheated by heat exchange with the furnace exhaust gas, thus improving thermal efficiency.
- Feed Preheat - Use of heat exchangers to increase the incoming temperature of the feed, thereby reducing furnace firing demand.
- Minimize Steam to Hydrocarbon Ratio - Minimizing steam to hydrocarbon ratio reduces the furnace firing.

Good Operating and Maintenance Practices

Good operation and maintenance practices for the steam cracking furnaces extend the performance of the combustion equipment, which reduces fuel gas usage and subsequent GHG emissions. Operating and maintenance practices have a significant impact on performance, including its efficiency, reliability, and operating costs.

Examples of good operating and maintenance practices include good air/fuel mixing in the combustion zone; sufficient residence time to complete combustion; proper fuel gas supply system operation in order to minimize fluctuations in fuel gas quality; good burner maintenance and operation; and overall excess oxygen levels high enough to safely complete combustion while maximizing thermal efficiency.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 309 °F. 365-day average, rolling daily	2012	PSD-TX-903-GHG

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Williams Olefins LLC, Geismar Ethylene Plant Geismar, LA	Ethylene Production	Energy Efficiency/Low -emitting Feedstocks/Lower-Carbon Fuels	Cracking heaters to meet a thermal efficiency of 92.5% Ethane/Propane to be used as feedstock Fuel gas containing 25% volume hydrogen on an annual basis	2012	PSD-LA-759
INEOS Olefins & Polymers U.S.A., Chocolate Bayou Plant Alvin, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 340 °F. Fuel will have ≤ 0.71 lbs carbon per lb of fuel (CC); 0.85 lbs GHG/lbs of ethylene. 365-day total, rolled daily.	2012	PSD-TX-97769-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for furnace limit flue gas exhaust temperature ≤ 350 °F. 12-month rolling average basis	2013	PSD-TX-748-GHG

BASF and Williams have differing processes for producing ethylene. BASF is a steam driven operation using multiple feedstocks, whereas Williams is utilizing electrical driven compressors and only ethane/propane as a feedstock which will require less energy consumption. This makes the Williams process more efficient than BASF. Since INEOS is only utilizing ethane gas as a feed, it can be compared to the Williams Olefins unit and has comparable furnace efficiency. The Williams Olefins unit has much smaller ethylene crackers than INEOS and utilizes electric power for their compressors in the downstream units. The ExxonMobil furnaces will be equipped with duct burners/heat recovery steam generators (HRSGs) and will have an exhaust temperature of 340°F or less during ethylene production. This value is within the range permitted at similar facilities. The minimum estimated furnace efficiency, for ExxonMobil's furnaces, during on-line operation is 92% based on a 2% casing heat loss and 340°F maximum stack temperature. This is approximately the same thermal efficiency as the Williams Olefins furnaces.

The following specific BACT practices are proposed for each furnace:

- *Energy Efficient Design* - Continuously monitor the steam cracking furnaces' exhaust stack temperature and control to a maximum stack exit temperature of 340°F on a 365-day rolling average basis, not including periods of startup, shutdown, and decoking.
- *Low Carbon Fuels* – Pipeline quality natural gas and a blended fuel gas will be utilized.
- *Good Operating and Maintenance Practices* – The use of good combustion practices includes periodic combustion tune-ups and maintaining the recommended combustion air and fuel ranges of the equipment as specified by its design, with the assistance of oxygen trim control.

BACT Limits and Compliance:

By implementing the operational measures above will equate to an emission limit for the furnaces of 987,968 tpy CO_2e. In addition to meeting the quantified emission limit, EPA is proposing that ExxonMobil will demonstrate compliance with energy efficient operations by continuously monitoring the exhaust stack temperature of each furnace. The maximum stack exit temperature of 340°F on a 365-day, rolling average basis will be calculated daily for each furnace.

ExxonMobil will demonstrate compliance with the CO_2e emission limit for the furnaces using the site specific fuel analysis for blended fuel gas utilizing an on-line gas composition analyzer and the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method, in which ExxonMobil may install, calibrate, and operate a CO_2 CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, site specific analysis of blended fuel gas, and the actual heat input (HHV). However, the emission limit is for all GHG emissions from the furnace, and is met by aggregating total emissions. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1, as published on October 30, 2009 (74 FR 56395). Records of the calculations would be required to be kept to demonstrate compliance with the CO_2e emission limit on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from at least four of the eight emission units to verify that the CO_2e limit will be met. The stack test will also monitor the exhaust stack temperature to ensure compliance with the BACT limit of 340°F on a 365-day rolling average. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emission are less than 0.01% of the total CO_2e emissions from the furnaces and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Decoking Activities (EPNs: XXAB-DEC, XXCD-DEC, XXEF-DEC, and XXGH-DEC)

The proposed steam cracking furnaces will require periodic decoking to remove coke deposits from the furnace tubes. Coke buildup is inherent in olefin productions. Removal of coke at optimal periods maintains the furnace at efficient ethane-to-ethylene conversion rates without increasing energy (fuel) demand. Decoking too early is unnecessary and results in excess shutdown/start-up cycles. Decoking too late results in fouled furnace tubes that reduce conversion rates and increases heat demand. The GHG emissions consist of CO_2 that is produced from combustion of the coke build up on the coils. GHG emissions from this operation are very low, less than 0.15% of the GHG emissions attributable to the project.

Step 1 – Identification of Potential Control Technologies

There are two known ways to minimize CO_2 generated from decoking operations:

- Limiting air/steam during the decoking process and
- Minimizing the amount of coke formed in the furnace through proper design and operation of the furnace.

There are no additional available add-on technologies identified in the RACT/BACT/LAER Clearinghouse (RBLC) that have been applied to furnace decoking operations to control CO_2 emissions once generated.

Step 2 – Elimination of Technically Infeasible Alternatives

Limiting air and/or steam and proper furnace design and operation to minimize coke formation are both considered technically feasible for the steam cracking furnaces.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Both options identified for controlling GHG emissions from decoking operations are considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, a ranking is not possible.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Limiting air and/or steam would reduce CO_2, but it would increase CO emissions from the process by driving the conversion of coke to CO rather than CO_2. Limiting air could also result in an incomplete decoke, which would lead to an increase in the frequency of decoke events. Because coke buildup acts as an insulator, its presence decreases the efficiency of the furnace, resulting in an increase in CO_2.

As noted above, coke formation is inherent to the design and operation of a steam cracking furnace. Decoking is performed once metallurgical or hydraulic limits are reached. The furnace coking rate will be minimized through design, control, and operations. The design will ensure good feed quality, conversion control, and heat distribution. Minimizing coke buildup is the key factor to reduce CO_2 emissions.

Step 5 – Selection of BACT

ExxonMobil proposes to incorporate a combination of design and recommended operation to limit coke formation in the tubes to the extent practicable considering ethane as a raw material. The steam cracking furnaces will be decoked approximately every 30 days. Timing and frequency of decokes depends on several factors including furnace tube pressure drop, furnace tube temperature, and safety considerations (e.g., force majeure or equipment malfunctions). These factors are monitored by operations personnel and/or by electronic means. Estimated CO_2 emissions from decoke operations is negligible compared to annual total from the furnaces. Managing coke buildup through such methods will result in limited CO_2 formation from periodic decoking operations.

XI. Train 5 Duct Burners (EPN: HRSG05)

The purpose of the duct burners is to generate incremental steam during times when the steam cracking furnaces are unable to meet the steam demand. The duct burners are configured in rows and will be fired at their design firing rate to create additional steam from natural gas firing. The duct burners will emit GHGs; 99% of the CO_2e emissions are CO_2.

Step 1 – Identification of Potential Control Technologies

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.
- *Use of Low Carbon Fuel* – Fuels containing lower concentrations of carbon generate less CO_2 emissions than higher carbon fuels.
- *Use of Good Operating and Maintenance Practices* –
  - *Periodic Visual Inspections-* The burner tips are visually inspected on an annual basis and cleaned when needed.
  - *Maintain Complete Combustion* - CO concentrations are continuously monitored by an on-line analyzer to ensure complete combustion.
  - *Oxygen Trim Control* - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- *Energy Efficient Design* –
  - *Use of an Economizer* - Use of a heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG Section boiler feedwater to attain thermal efficiency.
  - *HRSG Section Blowdown Heat Recovery* - Use of a heat exchanger to recover heat from HRSG Section blowdown to preheat feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.

- *Condensate Recovery* - Return of hot condensate for use as feedwater to the HRSG Section. Use of hot condensate as feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.

<u>Carbon Capture and Storage</u>

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and negative energy and environmental issues discussed in section IX above, CCS will not be considered further in this analysis.

Step 2 – Elimination of Technically Infeasible Alternatives

Use of a low carbon fuel is technically feasible. Pipeline quality natural gas is the lowest carbon fuel commercially available at the BOP. ExxonMobil does utilize a blended fuel gas in the furnaces. There is only enough blended fuel gas for use in the furnaces.

Oxygen trim control, feasible for stand-alone boilers, is not applicable to duct burners in Train 5 since gas turbine exhaust streams are the source of combustion air. Therefore, this option is eliminated on the basis of technical infeasibility.

All remaining options identified in Step 1 are considered technically feasible. An economizer, condensate return, blowdown heat recovery, and CO analyzer are already in use on the existing HRSG Section and will continue to be used; therefore, these alternatives are not addressed in Steps 3 and 4 of the analysis.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Natural gas is among the lowest-carbon fuels commercially available and is the only commercially available fuel source at the BOP. As stated earlier, blended fuel gas is available, but not in a large enough quantity.

The remaining technology not already included in the existing HRSG configuration is periodic inspection of the burners. The energy efficiency improvement of burner inspections cannot be directly quantified.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of natural gas in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Periodic Visual Inspections

Performing regular visual inspections of the burners can ensure proper operation of the duct burners which can have a positive effect on their operation ensuring proper combustion, although the effectiveness cannot be directly quantified. There are no significant adverse energy or environmental impacts associated with this control option.

Step 5 – Selection of BACT

To date, other facilities with a similar source given a GHG BACT limit are summarized in the table below:

Company / Location	Process Description	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
BASF FINA Petrochemicals LP, NAFTA Region Olefins Complex Port Arthur, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for gas turbine auxiliary duct burners - monitor and maintain a thermal efficiency of 60% 12-month rolling average basis	2012	PSD-TX-903-GHG

ExxonMobil proposes to maintain a minimum thermal efficiency of 70%. This limit is based on historical operational data of Train 5 and includes projected performance with the duct burners. This value is 10% higher than the thermal efficiency limit granted to a similar emission source as shown in the table above.

The following specific BACT practices are proposed for the duct burners to assure this level of thermal efficiency:

- *Low Carbon Fuels* – Consume pipeline quality natural gas, or a fuel with a lower carbon content than natural gas, as a fuel to the duct burners.

- *Good Operating and Maintenance Practices –*
    - *Perform and maintain records of online burner visual inspections annually and perform cleanings of the duct burner tips during planned shutdowns or as-needed, whichever comes first, to maintain thermal efficiency.*
    - *Calibrate and perform preventative maintenance checks on the duct burners' fuel flow meters annually.*
- *Energy Efficient Design*
    - *Maintain operation of the existing condensate recovery, HRSG Section blowdown heat recovery, and economizer as necessary to achieve an overall 70% thermal efficiency on a 12-month rolling average.*
    - *Demonstrate operational BACT for the duct burners by calculating the thermal efficiency of no less than 70% on a 12-month rolling average basis. Efficiency will be demonstrated by the following equation:*

$$Unit\ Efficiency = \frac{\begin{array}{c}Heat\ Content\ of\ Steam\ Produced\ + \\ Heat\ Content\ of\ Power\ Produced\end{array}}{Heat\ Content\ of\ Fuel\ Supply} \times 100\%$$

- CO_2e emissions from the duct burners will be determined based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Determine 12-month rolling average firing rates of the duct burners and recorded monthly.

BACT Limits and Compliance:

Using the operating practices above will result in an emission limit for the duct burners of 397,709 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_2e emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).

MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2, using the GWPs as published on October 30, 2009 (74 FR 56395), site specific analysis of process fuel gas, and the actual heat input (HHV).

XII. Staged Flaring Operation (EPNs: FLAREXX1 and FLAREXX2)

ExxonMobil will install a flare system with staged operation to provide for the safe control of gases vented from the proposed project during normal operations and during emergency releases. The flare system will consist of a steam-assisted elevated flare (FLAREXX1) and a multi-point ground flare (FLAREXX2). The staged flare system is designed to segregate the continuous flows (high volume) from the intermittent flows (low volume). Segregating these low and high volume streams into different flare dispositions will optimize the amount of gas and steam to hydrocarbon ratio required for good combustion. The elevated flare's pilots are fueled by pipeline quality natural gas and has a destruction and removal efficiency (DRE) of 98% for methane. The multi-point ground flare's pilots will be fueled by pipeline quality natural gas and/or ethane, and will have a DRE of 99%. The CO_2e emissions from the flare account for less than 7% of the total projects CO_2e emissions.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Assist Gas* – The flares will use pipeline quality natural gas and/or ethane for the pilots and as supplemental fuel, if needed, to maintain appropriate vent stream heating value.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment and operating within the recommended heating value and flare tip velocity as specified by its design.
- *Staged Flaring* – Use of staged flaring ensures the streams are mitigated appropriately and per design to achieve the stated DRE.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Low-Carbon Fuel
- Good Operation and Maintenance Practices
- Staged Flaring

Use of low-carbon fuel, and good operation and maintenance practices, and staged flaring are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practicable for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits as well.

Good Operation and Maintenance Practices

Good operation and maintenance practices effectively support the proper operation of the flares and are inherent in the design and operation of the proposed flare system.

Staged Flaring

Staged flaring is economically and environmentally practical for the proposed project.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the elevated flare:

- *Low Carbon Fuels* – The flares will combust pipeline natural gas and/or ethane in the pilots, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures.

- *Good Operation and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment, flare tip maintenance, operating within the recommended heating value, and flare tip velocity as specified by its design.
- *Staged Flaring* – A staged flare system will be utilized.

ExxonMobil proposes to monitor and record the following parameters to demonstrate continuous compliance with staged flare system operating specifications:

- Continuously monitor and record the pressure of the flare system header,
- Continuously monitor and record the flow to the elevated flare through a flow monitoring system,
- Continuously monitor the steam flow to the elevated flare through a flow monitoring system and record the steam to hydrocarbon ratio,
- Continuously monitor the composition of the waste gas contained in the flare system header through an online analyzer located on the common flare header, sufficiently upstream of the diverting headers to the elevated flare and the multi-point ground flare, and record the heating value of the flare system header,
- Continuously monitor the flow rate to the multi-point ground flare to demonstrate that flow routed to the multi-point ground flare system exceeds 4 psig; however, if a lower pressure can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented,
- Maintain a minimum heating value and maximum exit velocity that meets 40 CFR § 60.18 requirements for the routine streams routed to the elevated flare including the assist gas flow, and
- Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas (adjusted for hydrogen) routed to the multi-point ground flare system to ensure the intermittent stream is combustible; however, if a lower heating value limit can be demonstrated to achieve the same level of combustion efficiency, then this lower limit will be implemented.

Using these operating practices above will result in an emission limit for the staged flare system of 90,539 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_{2e} emission limit using the emission factors for natural gas from 40 CFR Part 98, Subpart C, Table C-1, and the site specific fuel analysis for ethane and waste gas (see Tables 3-3C and 3-3D of the GHG permit application). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = DRE \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).
DRE = Assumed combustion efficiency of the flare.
0.001 = Unit conversion factor (metric tons per kilogram, mt/kg).
n = Number of measurement periods. The minimum value for n is 52 (for weekly measurements); the maximum value for n is 366 (for daily measurements during a leap year).
p = Measurement period index.
44 = Molecular weight of CO_2 (kg/kg-mole).
12 = Atomic weight of C (kg/kg-mole).
$(Flare)_p$ = Volume of flare gas combusted during the measurement period (standard cubic feet per period, scf/period). If a mass flow meter is used, measure flare gas flow rate in kg/period and replace the term "$(MW)_p/MVC$" with "1".
$(MW)_p$ = Average molecular weight of the flare gas combusted during measurement period (kg/kg-mole). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
MVC = Molar volume conversion factor (849.5 scf/kg-mole).
$(CC)_p$ = Average carbon content of the flare gas combusted during measurement period (kg C per kg flare gas). If measurements are taken more frequently than daily, use the arithmetic average of measurement values within the day to calculate a daily average.
1.102311 = Conversion of metric tons to short tons.

The GHG mass emission limits in TPY associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2 using the GWPs as published on October 30, 2009 (74 FR 56395), site specific analysis of waste gas, and the actual heat input (HHV).

XIII. Engines (EPNs: DIESELXX01, DIESELXX02, DIESELXX03, DIESELXX04, DIESELXX05, DIESELXXFW1, and DIESELXXFW2)

ExxonMobil will install up to five backup generators and two firewater booster pump engines. The backup generators shall have an aggregate power output not to exceed 3.0 MW total, regardless of how many are installed. The generators and engines proposed for use will operate at a low annual capacity factor - approximately one hour per week in non-emergency use. The generators and engines are designed to use diesel fuel, stored in onsite tanks, so that emergency power is available for safe shutdown of the facility in the event of a power outage that may also include natural gas supply curtailments. The firewater booster pump engines will supply power to two new booster pumps that will be added to the existing firewater system. Each firewater booster pump engine will have a power output of 0.45 MW (600 HP) each. The CO_2e emissions from the emergency generators and the two firewater booster pump engines account for less than 0.01% of the total project emissions.

Step 1 – Identification of Potential Control Technologies

- *Low Carbon Fuels* – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.
- *Good Operating and Maintenance Practices* – Good operating and maintenance practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engines is to provide a power source during emergencies, which include site power outages and natural disasters, such as hurricanes. As such, the power source must be available during emergencies. Electricity is not a source that is available during a power outage, which is the specific event for which the backup generators are designed to operate. Natural gas supply may be curtailed during an emergency such as a hurricane; thereby not providing fuel to the engines during the specific event for which the backup generators and firewater booster pump are designed to operate. The engines must be powered by a liquid fuel that can be stored in a tank and supplied to the engines on demand, such as motor gasoline or diesel. Therefore, ExxonMobil proposes to use diesel fuel for the emergency generator engines and firewater booster pump engines, since non-volatile fuel must be used for emergency operations. The use of low-carbon fuel is considered technically infeasible for emergency generator operation and is not considered further for this analysis.
- *Good Operating Combustion Practices and Maintenance* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Only one option, good operation and maintenance practices, has been identified for controlling GHG emissions from engines; therefore, ranking by effectiveness is not applicable.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

The single option for control of CO_2 from engines is to follow good operating and maintenance practices.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the engines:

- *Good Operation and Maintenance Practices* – Good operation and maintenance practices for compression ignition engines include appropriate maintenance of equipment, periodic testing conducted weekly, and operating within the recommended air to fuel ratio, as specified by its design.

Using the operating and maintenance practices identified above results in a BACT limit of 952 tpy CO_2e for all engines combined. ExxonMobil will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98, Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(ii) is as follows:

$$CO_2 = \frac{44}{12} * Fuel * CC * 0.001 * 1.102311$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of diesel fuel (short tons)
Fuel = Annual volume of the liquid fuel combusted (gallons). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the liquid fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Subpart C, Table C-2.

XIV. Equipment Fugitives (EPN: BOPXXAREA)

The proposed project will include new piping components for movement of gas and liquid raw materials, intermediates, and feedstocks. These components are potential sources of GHG emissions due to emissions from rotary shaft seals, connection interfaces, valves stems, and similar points. GHGs from piping component fugitives are mainly generated from fuel gas and natural gas lines for the proposed project, but may be emitted from other process lines that are in VOC service.

Step 1 – Identification of Potential Control Technologies

- *Leakless/Sealless Technology*
- *Instrument LDAR Programs*
- *Remote Sensing*
- *Auditory, Visual, and Olfactory (AVO) Monitoring*

Step 2 – Elimination of Technically Infeasible Alternatives

- *Leakless/Sealless Technology* – Leakless technology valves may be incorporated in situations where highly toxic or otherwise hazardous materials are present. These technologies cannot be repaired without a unit shutdown that often generates additional emissions. Fuel gas and natural gas are not considered highly toxic nor hazardous materials, and do not warrant the risk of unit shutdown for repair and therefore leakless valve technology for fuel lines is considered technically impracticable.
- *Instrument LDAR Programs* – Is considered technically feasible.
- *Remote Sensing* – Is considered technically feasible.
- *AVO Monitoring* – Is considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Instrument LDAR programs and remote sensing using an infrared camera have been determined by EPA to be equivalent methods of piping fugitive controls.[4] The most stringent TCEQ LDAR program, 28LAER, provides for 97% control credit for valves, flanges, and connectors.

As-observed audio and visual observations (AVO) means of identifying fugitive emissions are dependent on the frequency of observation opportunities. These opportunities arise as technicians make inspection rounds. Since pipeline natural gas is odorized with very small quantities of mercaptan, as-observed olfactory observation is a very effective method for identifying fugitive

[4] 73 FR 78199-78219, December 22, 2008.

emissions at a higher frequency than those required by an LDAR program and at lower concentrations than remote sensing can detect.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective, with Consideration of Economic, Energy, and Environmental Impacts

As-observed AVO is the most effective approach for GHG sources that are not in VOC service, such as natural gas components. The frequency of inspection rounds and low odor threshold of mercaptans in natural gas make as-observed AVO an effective means of detecting leaking components in natural gas service. The approved LDAR program already implemented at BOP is an effective control for GHG sources that are in VOC service, since these components are monitored in accordance with the existing LDAR program and may not be easily detectable by olfactory means.

Instrument LDAR and/or remote sensing of piping fugitive emissions in fuel gas and natural gas service may be effective methods for detecting GHG emissions from fugitive components; however, the economic practicability of such programs cannot be verified. Specifically, fugitive emissions are estimates only, based on factors derived for a statistical sample and not specific neither to any single piping component nor specifically for natural gas service. Therefore, instrument LDAR programs or their equivalent alternative method, remote sensing, are not economically practicable for controlling the piping fugitive GHG emissions from the project's natural gas components.

Step 5 – Selection of BACT

Based on the economic impracticability of instrument monitoring and remote sensing for fuel gas and natural gas piping components, ExxonMobil proposes to incorporate as-observed AVO as BACT for the piping components associated with this project in fuel gas and natural gas service. The proposed permit contains a condition to implement an AVO program on a weekly basis.

Process lines in VOC service contain a minimal quantity of GHGs. Additionally, process lines in VOC service are proposed to incorporate the TCEQ 28VHP leak detection and repair (LDAR) program for fugitive emissions control in the New Source Review (NSR) permit No. 102982 to be issued by TCEQ. EPA concurs with ExxonMobil's assessment that using the TCEQ 28VHP[5] LDAR program is an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being

[5] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf. These conditions are included in the TCEQ issued NSR permit.

imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XV. Endangered Species Act

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant, ExxonMobil, and its consultant, Raven Environmental Services, INC., ("Raven"), and adopted by EPA.

A draft BA has identified twelve (12) species listed as federally endangered or threatened in Harris County, Texas:

Federally Listed Species for Harris County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Plant	
Texas Prairie Dawn Flower	*Hymenoxys texana*
Birds	
Red-cockaded Woodpecker	*Picoides borealis*
Whooping Crane	*Grus americana*
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Louisiana Black Bear	*Ursus americanus luteolus*
Red Wolf	*Canis rufus*
Amphibians	
Houston Toad	*Bufo houstonensis*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Hawksbill Sea Turtle	*Eretmochelys imbricate*

EPA has determined that issuance of the proposed permit will have no effect on any of the twelve (12) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. Magnuson-Stevens Fishery Conservation and Management Act

The 1996 Essential Fish Habitat (EFH) amendments to the Magnuson-Stevens Fishery Conservation and Management Act (Magnuson-Stevens Act) set forth a mandate for NOAA's National Marine Fisheries Service (NMFS), regional fishery management councils (FMC), and other federal agencies to identify and protect important marine and anadromous fish habitat.

To meet the requirements of the Magnuson-Stevens Act, EPA is relying on an EFH Assessment prepared by the Whitenton Group on behalf of ExxonMobil and reviewed and adopted by EPA.

The facility is adjacent to tidally influenced portions of the Houston Ship Channel (San Jacinto Tidal). These tidally influenced portions have been identified as potential habitats of postlarval, juvenile, subadult or adult stages of red drum (*Sciaenops ocellatus*), shrimp (4 species), coastal migratory pelagics (3 species), and reef fish (43 species). The EFH information was obtained from the NMFS's website (http://www.habitat.noaa.gov/protection/efh/efhmapper/index.html).

Furthermore, these tidally influenced areas have also been identified by NMFS to contain EFH for neonate/young of the year scalloped hammerhead sharks (*Sphyrna lewini*); neonate/young of the year and juvenile blacktip sharks (*Carcharhinus limbatus*) and bull sharks (*Carcharhinus leucas*); and neonate/young of the year and adult Atlantic sharpnose sharks (*Rhizoprionodon terraenovae*) and bonnethead sharks (*Sphyrna tiburo*)

Based on the information provided in the EFH Assessment, EPA concludes that the proposed PSD permit allowing ExxonMobil construction of a new ethylene production unit within the existing Baytown facility will have no adverse impacts on listed marine and fish habitats. The assessment's analysis, which is consistent with the analysis used in the BA discussed above, shows the project's construction and operation will have no adverse effect on EFH.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final essential fish habitat report can be found at EPA's Region 6 Air Permits website at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVII. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on and adopted a cultural resource report prepared by Atkins on behalf of ExxonMobil submitted on April 8, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 25 acres of land within and adjacent to the construction footprint of the existing facility. Atkins conducted a field survey of the property, and a visual impacts survey and desktop review within a 1.5-mile radius area of potential effect (APE). The desktop review included an archaeological background and historical records review using the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the results of the field survey, no archaeological resources or historic structures were found within the APE. Based on the visual survey and cultural review, one historic site was identified to be potentially eligible for listing on the National Register, but it is outside the APE (approximately 1.5 miles away).

EPA Region 6 determines that because no historic properties are located within the APE and that a potential for the location of archaeological resources within the construction footprint itself is low, issuance of the permit to ExxonMobil will not affect properties potentially eligible for listing on the National Register.

On April 9, 2013, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit. EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVIII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGS at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XIX. Conclusion and Proposed Action

Based on the information supplied by ExxonMobil, our review of the analyses contained the TCEQ NSR Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue ExxonMobil a PSD permit for GHGs for the facility, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month total, rolling monthly, shall not exceed the following:

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
XXAF01 XXBF01 XXCF01 XXDF01 XXEF01 XXFF01 XXGF01 XXHF01	XXAF01-ST XXBF01-ST XXCF01-ST XXDF01-ST XXEF01-ST XXFF01-ST XXGF01-ST XXHF01-ST	Steam Cracking Furnaces	CO_2	982,000[3]	987,968[3]	Furnace Gas Exhaust Temperature ≤ 340 °F. Each furnace limited to a maximum firing rate of 515 MMBtu/hr. See permit conditions III.A.1.h. and j.
			CH_4	48[3]		
			N_2O	16[3]		
XXAB-DEC XXCD-DEC XXEF-DEC XXGH-DEC	XXAB-DEC XXCD-DEC XXEF-DEC XXGH-DEC	Furnace Decoke Vents	CO_2	796[4]	2,120[4]	Proper furnace design and operation. See permit conditions III.A.1.a. through III.A.1.l.
			CH_4	4[4]		
			N_2O	4[4]		
FLAREXX1 FLAREXX2	FLAREXX1 FLAREXX2	Staged Flare System	CO_2	86,574[5]	90,539[5]	Use of Good Combustion Practices. See permit condition III.A.3.
			CH_4	115[5]		
			N_2O	5[5]		
HRSG05	HRSG05	Train 5 Duct Burners	CO_2	397,231	397,709	Maintain a minimum thermal efficiency of 70%. See permit condition III.A.2.g.
			CH_4	8		
			N_2O	1		
DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	DIESELXX01 DIESELXX02 DIESELXX03 DIESELXX04 DIESELXX05	Backup Generator Engines	CO_2	223[6]	554[6]	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
			CH_4	1[6]		
			N_2O	1[6]		
DIESELXXFW1 DIESELXXFW2	DIESELXXFW1 DIESELXXFW2	Firewater Booster Pump Engines	CO_2	67[7]	398[7]	Use of Good Operating and Maintenance Practices. See permit condition III.A.4.
			CH_4	1[7]		
			N_2O	1[7]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[1,2]	BACT Requirements
				TPY[1]		
BOPXXFUG	BOPXXFUG	Fugitive Emissions	CH_4	No Emission Limit Established[8]	No Emission Limit Established[8]	Implementation of LDAR/AVO program. See permit condition III.A.5.
Totals[9]			**CO_2**	**1,466,916**	**CO_2e 1,479,665**	
			CH_4	**179**		
			N_2O	**29**		

1. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
2. Global Warming Potentials (GWP): $CH_4 = 21$, $N_2O = 310$
3. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the steam cracking furnaces applies for all eight furnaces combined.
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the furnace decoke vents is for all four furnace decoke vents combined.
5. The GHG Mass Basis TPY limit and the CO_2e TPY limit are for the entire staged flare system (EPNs: FLAREXX1 and FLAREXX2).
6. Up to five generators are allowed, however; total power output will not exceed 3.0 MW for all generators combined. The GHG Mass Basis and CO_2e TPY emissions stated in this table are for all Emergency Generator Engines combined regardless of the number installed.
7. The GHG Mass Basis and CO_2e TPY emissions stated in this table are for both Firewater Booster Pump Engines (EPNs: DIESELXXFW1 and DIESELXXFW2) combined.
8. Fugitive process emissions from EPN BOPXXFUG are estimated to be 1 TPY of CH_4 and 21 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
9. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.