ExxonMobil Chemical Company
Mont Belvieu Plastics Plant
13330 Hatcherville Road
Mont Belvieu, Texas 77580-9532

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
Mont Belvieu Plastics Plant
Permit PSD-TX-103048-GHG
Polyethylene Production Unit

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AIR PERMITS SECTION
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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 polyethylene production unit at the Mont Belvieu Plastic Plant (MBPP), an existing major stationary source of criteria pollutants. The proposed project consists of emission units such as flameless thermal oxidizers, a regenerative thermal oxidizer, an elevated flare, a multi-point ground flare, two boilers, and equipment leak fugitives. 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. 103048 on October 7, 2013. EPA Region 6 issued Permit PSD-TX-103048-GHG on September 5, 2013, 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. MBPP demonstrated through contemporaneous period netting that all emissions were below their respective PSD and Nonattainment New Source Review major modification thresholds, as documented in TCEQ's Construction Permit Source Analysis & Technical Review for the initial application for Permit No. 103048 (TCEQ Project 178209).[2] EPA issued the PSD Permit in September 2013, recognizing that Permit No. 103048 is a minor NSR permit for non-GHG pollutants.[3] Therefore, ExxonMobil is hereby submitting this request for rescission of PSD Permit PSD-TX-103048-GHG, pursuant to 40 CFR § 52.21(w)(2)(iii).

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[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 "Emission Summary" 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-103048-GHG in Attachment 2.

Supporting documents enclosed are:

- Attachment 1: a copy of the minor New Source Review (NSR) Permit 103048 and the Source Analysis & Technical Review for TCEQ Project No. 178209, both issued by the TCEQ;
- Attachment 2: a copy of the Statement of Basis for Permit PSD-TX-103048-GHG, issued by EPA.

I hereby certify that PSD Permit PSD-TX-103048-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. 103048
- TCEQ Construction Permit Data Analysis & Technical Review for Project 178209

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
AIR QUALITY PERMIT

A Permit Is Hereby Issued To
Exxon Mobil Corporation
Authorizing the Construction and Operation of
Mont Belvieu Plastics Plant
Located at **Mont Belvieu, Chambers County, Texas**
Latitude 29° 52′ 43″ Longitude 94° 55′ 12″

Permit: 103048

Issuance Date : October 7, 2013

Renewal Date: October 7, 2023

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 103048

1. This permit authorizes chemical manufacturing operations for the Polyethylene Unit PEX located at Mont Belvieu, Chambers County, Texas.

   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.

   Planned startup and shutdown emissions due to the activities identified in Special Condition No. 20 are authorized from facilities and emission points identified in Attachment D provided the facility and emissions are compliant with the MAERT and special conditions.

Federal Applicability

2. 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 DDD, Standards of Performance for Volatile Organic Compound (VOC) Emissions from the Polymer Manufacturing Industry.

3. These facilities shall comply with all applicable requirements of the U.S. Environmental Protection Agency (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 FFFF, National Emission Standard for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing.

   C. Subpart DDDDD, National Emission Standards for Hazardous Air Pollutants for Industrial, Commercial, and Institutional Boilers and Process Heaters.

4. If any condition of this permit is more stringent than the applicable regulations in Special Condition Nos. 2 and 3 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

5. Production from polyethylene unit PEX are limited as follows:

A. Polyethylene production shall not exceed the rates represented in the confidential section of the Permit Number 103048 application supplement dated December 21, 2012.

B. Records of the 12-month rolling total production of polyethylene shall be maintained.

6. Fuel fired in the combustion sources [Emission Point Number(s) (EPNs) RUPK31, RUPK32, 3UF61A, 3UF61B, 3UF61C, 3UFLARE62, 3UFLARE63 and RUPK71] shall be pipeline quality natural gas containing no more than 5 grains of total sulfur per 100 dry standard cubic feet (dscf).

7. The boilers (EPNs RUPK31 and RUPK32) shall be designed and operated in accordance with the following requirements:

A. The permit holder shall install and operate a fuel flow meter to measure the gas fuel usage for each boiler. 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.

B. Except as specified in Special Condition No. 29.B, Emissions from boilers (EPNs RUPK31 and RUPK32) shall not exceed the following:

Pollutant	24-hour rolling average	12-month rolling average
NO_x	0.025 lb/MMBtu	0.010 lb/MMBtu (HHV)
CO	100 ppmvd corrected to 3% oxygen	50 ppmvd, corrected to 3% oxygen
Ammonia (NH_3)	15 ppmvd corrected to 3% oxygen	10 ppmvd, corrected to 3% oxygen

8. The regenerative thermal oxidizer (RTO) (EPN RUPK71) shall achieve a VOC destruction efficiency of 99% or an outlet VOC concentration of less than 10 ppmv on a dry basis.

A. The RTO firebox exit temperature shall be maintained a minimum of 1400°F while waste gas is being fed into the oxidizer prior to initial stack testing. After the initial stack test has been completed, the six minute average RTO firebox exit temperature shall be at greater than the respective hourly average maintained during the most recent satisfactory stack testing required by Special Condition No. 35.

B. The RTO firebox exit temperature shall be continuously monitored and recorded when in operation. The temperature measurement device shall reduce the temperature readings to an averaging period of six minutes or less and record it 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.

C. Quality assured (or valid) data must be generated when the RTO 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 minutes) that the regenerative oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

D. During periods of RTO downtime, emissions shall be vented directly to atmosphere (EPN RUPK71MSS). The period during which uncontrolled VOC emissions are vented directly to atmosphere (EPN RUPK71MSS) shall not exceed 263 hours on a rolling 12-month basis.

9. The flameless thermal oxidizers (FTO) (EPNs 3UF61A/B/C) shall achieve a VOC destruction efficiency of 99.99%.

A. The FTO firebox exit temperature shall be maintained at a minimum of 1400°F while waste gas is being fed into the oxidizer prior to initial stack testing. After the initial stack test has been completed, the six minute average FTO firebox exit temperature and six minute average exhaust oxygen concentration shall be at greater than the respective hourly average maintained during the most recent satisfactory stack testing required by Special Condition No. 35.

B. The FTO firebox exit temperature shall be continuously monitored and recorded while in operation. The temperature measurement device shall reduce the temperature readings to an averaging period of 6 minutes or less and record it 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.

C. Quality assured (or valid) data must be generated when the thermal oxidizer 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 minutes) that the thermal oxidizer operated over the previous rolling 12 month period. The measurements missed shall be estimated using engineering judgment and the methods used recorded.

10. The PEX Analyzers (EPN PEXANALZ) shall have catalyst canisters replaced annually or per manufacturer specifications.

11. The elevated flare (EPN 3UFLARE62) 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 the 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.

12. The multi-point ground flare (EPN 3UFLARE63) shall be designed and operated in accordance with the following requirements:

    A. The flare shall maintain a VOC destruction efficiency (DRE) of 99.5% or greater at all times that the flare is in operation.

    B. The flare system shall be designed such that the process gas stream to the flare meets one of the following:

        (1) 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.

        (2) The conditions of an Alternate Means of Control issued in accordance with Special Condition No. 37 of this permit.

    C. The flare shall be operated with a flame present at all times when process gas is being sent to the flare and have a constant pilot flame capable of lighting all multi-point burners(tips). 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.

D. 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. Steam assist is not authorized for the EPN 3UFLARE63.

E. The permit holder shall install continuous flow monitor(s), heating value (Btu) analyzer and pressure monitor that provide a record of the vent stream flow composition and pressure to the flare. A flow monitor sensor and analyzer sample point(s) 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.

(1) Prior to operation, the permit holder shall submit to the TCEQ Regional Office a method to validate that waste gas will not pass uncombusted between stages of the multi-point ground flare.

(2) Flow monitor, heating value and pressure readings shall be taken at least once every 6 minutes and the average hourly values of the flow, composition and pressure shall be recorded each hour at all times when process gas is being sent to the flare.

(3) The flare header operating pressure shall be greater than 4 pounds per square inch gauge (psig) on a rolling one-hour basis at all times when process gas is being sent to the flare.

(4) The flare gas net heating value shall be greater than 800 British thermal units per standard cubic foot (Btu/scf) on a rolling one-hour basis at all times when process gas is being sent to the flare.

(5) The time, date and duration of any failure to maintain the limits for pressure and heating value as required by Special Condition Nos. 12.E(3) and 12.E(4) shall be recorded.

(6) During periods when the pressure and/or heating value requirements in Special Condition Nos. 12.E(3) and 12.E(4)are not met, emissions shall be calculated based on a DRE of 98% for all constituents.

(7) The monitors shall be calibrated on an annual basis to meet the following accuracy specifications: the flow monitor shall be ±5.0%, 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.

(8) 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).

(9) 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.

(10) 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.

(11) The Permit holder shall install a camera to monitor the EPN RUFLARE63 when vent gas is being sent to the flare.

(12) The permittee may alter, with Executive Director approval, the operating, monitoring, and recordkeeping requirements of this condition based on the results of the approved testing conducted in accordance with Special Condition No. 13.

13. Prior to start of operation, the permit holder shall perform testing to demonstrate that a destruction efficiency of 99.5% or greater will be achieved by the multi-point ground flare (EPN 3UFLARE63).

A. The permit holder shall prepare a testing protocol for review by the TCEQ Office of Air, Air Permits Division, and the TCEQ Regional Office no later than 90 days prior to the scheduled date of the test. The protocol shall include:

(1) Proposed date for pretest meeting.

(2) Date testing will occur.

(3) Location where testing will occur.

(4) Name of firm conducting testing.

(5) Type of testing equipment to be used.

(6) Method or procedure to be used in testing.

(7) Proposed testing procedures.

(8) Procedure/parameters to be used to ensure representative operations.

B. The permit holder shall arrange for a pretest meeting with participation from the TCEQ Office of Air, Air Permits Division, and TCEQ Regional Office. The purpose of the 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.

C. The permit holder shall not proceed with testing without written approval of the protocol by the TCEQ Office of Air, Air Permits Division.

The permit holder shall complete the testing and submit a test report no later than 180 days prior to the start of operation of EPN 3UFLARE63 to the TCEQ Office of Air, Air Permits Division, TCEQ Regional Office and each local air pollution control program.

D. The permit holder is responsible for providing for sampling and testing facilities and conducting the sampling and testing operations at his expense.

14. All particulate matter (PM) control systems shall comply with the following:

A. All PM control systems shall be designed to effectively capture emissions from associated equipment and prevent particulate emissions from escaping.

B. Each PM emission capture system shall be maintained free of holes, cracks, and other conditions that would reduce the collection efficiency of the emission capture system.

C. All appropriate PM control devices and associated emission capture system covered by this permit shall be maintained in good working order and operated during normal facility operations.

D. Particulate matter from the exhaust vent of a control device that uses a filter or filters shall not exceed 0.01 grain per dry standard cubic foot (dscf) of air from any vent. This shall be ensured by not having any visible emissions from the exhaust vent of the filtered control device as determined using U.S. Environmental Protection Agency (EPA) Test Method 22. Inspections for visible emissions from each filtered control device shall occur once each day when the control device is in operation. The definition of visible emissions shall be in accordance with EPA Test Method 22.

When there are visible emissions from any one filtered vent, the operation associated with that particular filtered vent shall be isolated and shut down in a timely and orderly manner. The isolated filter system shall be tested and inspected. Failed or damaged parts shall be repaired or replaced.

E. There shall not be any visible emissions from the exhaust vent of any cyclone as determined using EPA Test Method 22. Inspections for visible emissions from each cyclone shall occur once each day when the control device is in operation. The definition of visible emissions shall be in accordance with EPA Test Method 22.

When there are visible emissions from any one cyclone vent, the operation associated with that particular control device shall be isolated and shut down in a timely and orderly manner. The isolated cyclone system shall be tested and inspected. Failed or damaged parts shall be repaired or replaced.

F. A spare parts filter inventory shall be maintained at the site for this facility.

G. Records shall be maintained of all inspections and maintenance performed.

15. The cooling tower (EPN RUCT01) 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. 15.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:

$TDS = \text{Conductivity} \times \text{Conversion Factor} (CF_{TDS})$

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. 15.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 monthly in accordance with 30 TAC §115.764 or an approved equivalent sampling method.

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 0.001% drift or less, and shall be maintained and inspected at least annually with a record of the inspection and all repairs.

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

17. 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.

18. Alternative requirements for the equipment specified in Special Condition No. 17:

A. In addition to the methods identified in Special Condition No. 17A, 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 addition to the specifications in Special Condition No. 17E, new and reworked piping connections may consist of pressed and permanently formed metal-to-metal seals.

C. In lieu of the requirements specified in Special Condition No. 17E, 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.

D. 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.

19. 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. 17.F through 17.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.

20. 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

21. This permit authorizes the emissions from the facilities identified in Attachment D for the planned maintenance, startup, and shutdown (planned MSS) activities summarized in the MSS Activity Summary (Attachment C) attached to this permit.

Sitewide inherently low emitting MSS activities are authorized in Permit No. 19016 and subject to Special Conditions and Emission Limits therein.

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 Attachment B and the emissions associated with it shall be recorded and include at least the following information:

A. Process unit at which emissions from the MSS activity occurred, including the emission point number and common name of the process unit;

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

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

D. The date and time of the 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.

All MSS emissions shall be summed monthly and the rolling 12-month emissions shall be updated on a monthly basis.

22. Process units and facilities, with the exception of those identified in Special Condition Nos. 24, 25, and 27 shall be depressurized, emptied, degassed, and placed in service in accordance with the following requirements.

A. The process equipment shall be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing, or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.044 psi at the normal process temperature and 68°F may be opened to atmosphere and drained in accordance with paragraph C of this special condition. The vapor pressure at 95°F may be used if the actual temperature of the liquid is verified to be less than 95°F and the temperature is recorded.

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 psi at either the normal process temperature or 68°F, any vents in the system must be routed to a control device or a controlled recovery system. Control must 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 must 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 must be drained into a closed vessel or closed liquid recovery system unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of being drained.

D. If the VOC partial pressure is greater than 0.044 psi at the normal process temperature or 68°F, facilities 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, except as necessary to verify an acceptable VOC concentration and establish isolation of the work area, until the VOC concentration has been verified to be less than 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 (process flow diagrams [PFDs] or piping and instrumentation diagrams [P&IDs] may be used to demonstrate compliance with the requirement). 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. 22. 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. If there is not a connection (such as a sample, vent, or drain valve) available from which a representative sample may be obtained, a sample may be taken upon entry into the system after degassing has been completed. The sample shall be taken from inside the vessel so as to minimize any air or dilution from the entry point. 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

LEL. Documented site procedures used to de-inventory equipment to a control device for safety purposes (i.e., hot work or vessel entry procedures) that achieve at least the same level of purging may be used in lieu of the above.

E. Gases and vapors with a VOC partial pressure greater than 0.044 psi 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 lb of air contaminants to be vented to atmosphere during shutdown or startup, as applicable.

All instances of venting directly to atmosphere per Paragraph E of this condition 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 MSS activities identified in Attachment B.

23. Air contaminant concentration shall be measured using an instrument/detector meeting one set of requirements specified below.

A. VOC concentration shall be measured using an instrument meeting all the requirements specified in EPA Method 21 (40 CFR Part 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 (RF) 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. If the RF of the VOC (or mixture of VOCs) to be monitored is greater than 2.0, the VOC concentration shall be determined as follows:

VOC Concentration = Concentration as read from the instrument*RF

In no case should a calibration gas be used such that the RF of the VOC (or mixture of VOCs) to be monitored is greater than 5.0.

(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, recording VOC concentration each minute. As an alternative the VOC concentration may be monitored over a five-minute period with an instrument designed to continuously measure concentration and record

the highest concentration read. The highest measured VOC concentration shall be recorded and 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 as defined in (3) is less than 80 percent of the range of the tube and 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 two samples taken at least five minutes apart must satisfy the following prior to uncontrolled venting:

measured contaminant concentration (ppmv) less than 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.

(1) The detector shall be calibrated within 30 days of use with a certified pentane gas standard at 25 percent of the LEL for pentane. Records of the calibration date and time and the calibration result (pass/fail) shall be maintained.

(2) A functionality test shall be performed on each detector within 24 hours of use with a certified gas standard at 25% of the LEL for pentane. The LEL detector shall read no lower than 90 percent of the calibration gas certified value. Records, including the date/time and the test results shall be maintained.

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

24. This condition applies only to piping and components subject to leak detection and repair monitoring requirements identified in NSR permits. 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:

    A. a cap, blind flange, plug, or second valve must be installed on the line or valve; or

    B. 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 at the end of 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.

25. This permit authorizes emissions from VOC storage tanks with an internal floating roof identified in the attached facility list 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. Emissions from change of service tank landings, for which the tank is not cleaned and degassed, 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.

    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 psi 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. The tank shall not be opened except as necessary to set up for degassing and cleaning. 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 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 air contaminants 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 makeup air introduced into the control device or recovery system. The VOC sampling and analysis shall be performed as specified in Special Condition No. 22.

(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 or ventilated without control, except as allowed by (1) or (2) below until one of the criteria in part D of this condition is satisfied.

(1) Minimize air circulation in the tank vapor space.

(a) One manway may be opened to allow access to the tank to remove or de-volatilize the remaining liquid. Other manways or access points may be opened as necessary to remove or de-volatilize the remaining liquid. Wind barriers shall be installed at all open manways and access points to minimize air flow through the tank.

(b) Access points shall be closed when not in use

(2) Minimize time and VOC partial pressure.

(a) The VOC partial pressure of the liquid remaining in the tank shall not 0.044 psi as documented by the method specified in part D.(1) of this condition;

(b) Blowers may be used to move air through the tank without emission control at a rate not to exceed 60,000 acfm for no more than 80 hours. All standing liquid shall be removed from the tank during this period.

(c) Records shall be maintained of the blower circulation rate, the duration of uncontrolled ventilation, and the date and time all standing liquid was removed from the tank.

D. The tank may be opened without restriction and ventilated without control, after all standing liquid has been removed from the tank or the liquid remaining in the tank has a VOC partial pressure less than 0.02 psia. These criteria shall 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 22.

(3) No standing liquid verified through visual inspection.

The permit holder shall maintain records to document the method used to release the tank.

E. Tanks shall be refilled as rapidly as practicable until the roof is off its legs with the following exceptions:

(1) Only one tank with a landed floating roof can be filled at any time at a rate not to exceed 233 bbl/hr.

(2) The vapor space below the tank roof is directed to a control device when the tank is refilled until the roof is within 10 percent of floating on the liquid to prevent liquid carry over. The control device used and the method and locations used to connect the control device shall be recorded. All vents from the tank being filled must exit through the control device.

F. The occurrence of each roof landing and the associated emissions shall be recorded and the rolling 12-month tank roof landing emissions shall be updated on a monthly basis. 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 floating roof landing.

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

(a) the 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 psi;

(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 floating 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 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.

26. The following requirements apply to vacuum and air mover truck operations to support planned MSS at this site:

A. Prior to initial use, identify any liquid in the truck. Record the liquid level and document whether the VOC partial pressure is less than 0.044 psi at 68°F. After each liquid transfer, identify the liquid, the volume transferred, and its VOC partial pressure if greater than 0.044 psi at 68°F.

B. If vacuum pumps or blowers are operated when liquid is in or being transferred to the truck, the following requirements apply:

(1) If the VOC partial pressure of the liquid in or being transferred to the truck is greater than 0.044 psi at 68°F, the vacuum/blower exhaust shall be routed to a control device or a controlled recovery system.

(2) Equip fill line intake with a "duckbill" or equivalent attachment if the hose end cannot be submerged in the liquid being collected.

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

(a) For each liquid transfer made with the vacuum operating, record the duration of any periods when air may have been entrained with the liquid transfer. 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.

(b) If the vacuum truck exhaust is controlled with a control device other than an engine or oxidizer, VOC exhaust concentration upon commencing each transfer, at the end of each transfer, and at least every hour during each transfer shall be recorded, measured using an instrument meeting the requirements of Special Condition 22A or B.

C. Record 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 transferred for each pick-up are not maintained, the emissions shall be determined using the physical properties of the liquid vacuumed 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 vacuumed into the truck is less than 0.10 psi, 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 Paragraphs A through D of this condition do not apply.

27. The following requirements apply to frac, or 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. This requirement does not apply to tanks/vessels that only vent to atmosphere when being filled, sampled, gauged, or when removing material.

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

C. These requirements do not apply to vessels storing less than 450 gallons of liquid that are closed such that the vessel does not vent to atmosphere except when filling, sampling, gauging, or when removing material.

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 consecutive12-month period. This record must be updated by the last day of the month following. 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 0.1 psi at 95°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.

28. Additional occurrences of MSS activities authorized by this permit may be authorized under permit by rule only if conducted in compliance with this permit's procedures, emission controls, monitoring, and recordkeeping requirements applicable to the activity.

29. 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. Alternate requirements for emissions from routine emission points are identified below.

A. Combustion units, with the exception of flares, at this site are exempt from NO_x and CO operating requirements identified in special conditions of this permit and in other NSR permits 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. Start-up activities for the boilers shall be defined as the period beginning when fuel is introduced to the boiler and ending when the selective catalytic reduction (SCR) catalyst bed reaches its stable operating temperature. A planned startup for each boiler is limited to 13 hours at 25% or less of the maximum allowable firing rate.

C. Shutdown activities for the boilers shall be defined as the period beginning when the SCR catalyst bed first drops below its stable operating temperature and ending when fuel is removed from the boiler.

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

30. 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.

Controlled recovery systems identified in this permit shall be directed to an operating 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 of 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 carbon sampling frequency may be extended 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 and a permit deviation shall be recorded.

(3) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 22.A or B.

(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. Sufficient new activated carbon canisters shall be maintained at the site to replace spent carbon canisters such that replacements can be done in the above specified time frame.

(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 percent 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 canister.

B. 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.

C. 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 butane or propane to confirm the required destruction efficiency within the period specified in part iii below. VOC shall be measured in accordance with the applicable 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 that 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 No. 22A are also acceptable for this documentation.

(3) The engine shall be operated and monitored as specified below:

(a) If the engine is 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 (b) 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 No. 23A. 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.

(b) If an oxygen sensor-based AFR controller is not used, the engine exhaust to atmosphere shall be monitored continuously and the VOC concentration recorded at least once every 15 minutes when waste gas is directed to the engine. 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 method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 22.A. An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background. The MSS activity shall be stopped as soon as possible if 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. The engine must have been stack tested within the past 24 months in accordance with part ii of this condition.

D. A control device that meets the requirements of Special Condition Nos. 9, 11, or 12 during planned MSS activities

E. A liquid scrubbing system may be used upstream of carbon adsorption. A single carbon can or a liquid scrubbing system may be used as the sole control device if the requirements below are satisfied.

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

(2) The method of VOC sampling and analysis shall be by detector meeting the requirements of Special Condition 22.A.

(3) An alarm shall be installed such that an operator is alerted when outlet VOC concentration exceeds 100 ppmv above background. 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.

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 insure 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 No. 22.

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

31. 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 Condition Nos. 1 and 20 through 31 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.

Continuous Demonstration of Compliance

32. 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 from the boilers (EPNs RUPK31 and RUPK32).

A. The NO_x 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 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 boiler 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 boiler 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.

33. The NH_3 concentration in each boiler exhaust stack (EPNs RUPK31 and RUPK32) 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.B.

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.B.

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.B.

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.B.

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.B.

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

34. Residual VOC emissions from produced polyethylene shall not exceed 70 pounds per million pounds of product by weight (ppmw) on a rolling 12-month average basis.

A. The permit holder shall sample and test the polymer from each reactor train for residual VOC as follows:

(1) Collect three samples of pellets from each reactor train monthly when the reactor is running for the entire month. When the reactor is not running the entire month, collect a sample each week the reactor is running.

(2) Samples of pellets shall be taken after the PEX extruders.

(3) Sampling and testing of the polymer shall be performed using a headspace analysis method which measures the ppmw that might evolve off the product. Alternate sampling and testing methods shall be approved by the TCEQ Houston Regional Office.

B. Uncontrolled residual VOC emissions in pounds (lbs) shall be calculated on a calendar month basis no later than the end of the following calendar month by multiplying the average of the residual VOC (ppmw) for the samples for each reactor train by the production rate for the month.

C. The rolling 12-month average residual VOC emissions in ppmw for PEX polyethylene production shall be sum of the uncontrolled residual VOC emissions for the current month and the preceding 11 month period divided by the total PEX polyethylene production for for the current and preceding 11-month period.

D. Monthly records shall include the following:

(1) Date and time of each sample.

(2) Monthly total PEX polyethylene production.

(3) Measured total VOC concentration (ppmw) in the polymer collected after the extruders resulting from the analysis specified in 23.A(3).

(4) Calculated uncontrolled residual VOC emissions for each reaction line in lbs.

(5) Calculated rolling 12-month average residual VOC emissions in pounds per million pounds of product (lb/MMlbs).

(6) Calculated total rolling 12-month residual VOC emissions from all reaction lines in tons per year.

Initial Demonstration of Compliance

35. 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 one of the boilers (EPNs RUPK31 or RUPK32), the RTO (EPN RUPK71), and one of the FTOs (EPNs 3UF61A, 3UF61B or 3UF61C) 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 boilers to be tested include (but are not limited to) NO_x, CO, and NH_3. Air contaminants emitted from the thermal oxidizers to be tested include (but are not limited to) NO_X and CO.

(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.

(d) 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.

(e) 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

36. 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 boiler (EPNs RUPK31 and RUPK32) as required by Special Condition No.7.A. Records from CEMS or monitoring/testing to demonstrate compliance with the limits in Special Condition No.7.B.

B. Records of RTO firebox exit temperature as required by Special Condition No. 8.B. Records of hours to demonstrate compliance with Special Condition No. 8.D for the regenerative thermal oxidizer (EPN RUPK71).

C. Records of FTO firebox exit temperature as required by Special condition No. 9.B.

D. Records of catalyst change out as required by Special Condition No. 10.

E. For the elevated flare and multi-point ground flare (EPNs 3UFLARE62 and 3UFLARE63), records of pilot flame presence as specified in Special Conditions Nos. 11.B and 12.C. Records of vent stream flow and composition as required by Special Condition Nos. 11.D and 12.E.

F. PM collection system inspections and maintenance as required by Special Condition No. 14.G

G. Records of TDS concentration and recirculating water flow rate in the cooling tower (EPN RUCT01) as required by Special Condition No. 15.D.

H. Records of tank seal inspections and throughput as required by Special Condition Nos.16.D and 16.G.

I. Records demonstrating compliance with the requirements of 28VHP and 28CNTQ as specified in Special Condition Nos. 17 and 19.

J. Records of quality assurance calibration for the boilers (EPNs RUPK31 and RUPK32) CEMS as required by Special Condition Nos. 32 and 33.

K. Records demonstrating compliance for the VOC Residual (EPN MISCVENTS) as required by Special Condition No. 34.

L. Records of stack tests completed in accordance with Special Condition No. 35.

Alternate Means of Control (AMOC)

37. If a request for an AMOC is granted by the regulating authority (TCEQ or EPA) for the multi-point ground flare (EPN 3UFLARE63), the requirements of the approved AMOC shall supersede the requirements of Special Condition No. 12. The permit holder shall incorporate these conditions into the permit through an alteration no later than 90 days after approval of the AMOC.

Emissions Reduction Project

38. The permit holder shall not begin operation until creditable decreases of 52.98 tons per year of VOC, as detailed in the December 21, 2012 Application Supplement, have been achieved and made federally enforceable.

Dated: October 7, 2013

Attachment A

[Reserved]

Dated: October 7, 2013

Attachment B

MSS Activity Summary

Planned MSS activities performed with work orders. These include activities such as:

Pump repair/replacement/cleaning/inspection
Fugitive component (valve, pipe, flange) repair/replacement/cleaning/inspection
Compressor repair/replacement/cleaning/inspection
Heat exchanger repair/replacement/cleaning/inspection
Vessel repair/replacement/cleaning/inspection
Boiler, FTO, and RTO repair/replacement/cleaning/inspection

Dated: October 7, 2013

Attachment C

MSS Activity Summary

Facilities or Source Category	Description	Emissions Activity	EPN	FIN
All process units	Vacuum residual liquid from process line equipment using Air Mover Truck and Vacuum Truck	Emissions to atmosphere	PEXMSS	AIRMSS VACMSS
All process units	Open process equipment for planned maintenance	Emissions to atmosphere	PEXMSS	MAINSD MAINEQUIP
Floating roof storage tanks	Depressure and degas tanks with VOC vapor pressure of 0.044 psia or greater at 68°F	Route vapors to control	MAINDEG	PEXTK1 MAINDEG
All storage tanks	Tank cleaning, inspection, and maintenance	Emissions to atmosphere	PEXMSS	MAINSD MAINEQUIP PEXTK1
All storage tanks	Refill clean tank	Emissions to atmosphere	PEXMSS	MAINSD MAINEQUIP PEXTK1
Routine maintenance activities (see attached list)	Routine maintenance activities	Emissions to atmosphere	PEXMSS	MAINSD MAINEQUIP

Dated: October 7, 2013

Attachment D

Permit Emission Points By Source Category

This permit authorizes emissions from the following temporary facilities used to support planned MSS activities at permanent site facilities: vacuum trucks, air mover trucks, frac tanks, temporary vessels, and control devices such as an internal combustion engine, thermal oxidizer, flare, carbon adsorption system, liquid scrubbing system, or closed loop refrigerated vapor recovery system. Emissions from temporary facilities are authorized provided the temporary facility (a) does not remain on the plant site for more than 12 consecutive months, (b) is used solely to support planned maintenance, startup, and shutdown (MSS) activities at the permanent site facilities listed in this Attachment, and (c) does not operate as a replacement for an existing authorized facility.

This permit authorizes MSS emissions from the permanent site facilities identified below. The headings for each group of facilities (Process Units, Tanks, etc.) are used in the MSS Activity Summary (Attachment C) to identify all facilities in the respective group.

FIN	Description
PEX	PEX Polyethylene Unit

EPN	FIN	NAME
PEXTK1	PEXTK1	Hexene Internal Floating Roof Tank

Dated: October 7, 2013

Emission Sources - Maximum Allowable Emission Rates

Permit Number 103048

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)
RUPK31	Steam Boiler	VOC	0.53	--
		NO_x	2.45	--
		NO_x (MSS)	5.88	--
		CO	7.24	--
		SO_2	1.37	--
		PM	0.73	--
		PM_{10}	0.73	--
		$PM_{2.5}$	0.73	--
		NH_3	0.44	--
RUPK32	Steam Boiler	VOC	0.53	--
		NO_x	2.45	--
		NO_x (MSS)	5.88	--
		CO	7.24	--
		SO_2	1.37	--
		PM	0.73	--
		PM_{10}	0.73	--
		$PM_{2.5}$	0.73	--
		NH_3	0.44	--

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
RUPK31/RUPK32	Boiler Cap	VOC	--	1.4
		NO_x	--	2.75
		CO	--	9.61
		SO_2	--	3.64
		PM	--	1.94
		PM_{10}	--	1.94
		$PM_{2.5}$	--	1.94
		NH_3	--	1.17
RUPK71	Regenerative Thermal Oxidizer (RTO)	VOC	1.07	2.31
		NO_x	0.28	1.11
		CO	0.38	1.52
		SO_2	0.06	0.24
		PM	0.03	0.14
		PM_{10}	0.03	0.14
		$PM_{2.5}$	0.03	0.14
RUPK71MSS	RTO Downtime	VOC	34.84	2.29
3UF61A/B/C (6)	Flameless Thermal Oxidizer (FTO) System	VOC	3.99	(6)
		NO_x	30.62	(6)
		CO	111.82	(6)
		SO_2	1.9	(6)
		PM	0.05	(6)
		PM_{10}	0.05	(6)
		$PM_{2.5}$	0.05	(6)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3UFLARE62 (6)	Elevated Flare	VOC	733.92	(6)
		NO_x	154.08	(6)
		CO	613.63	(6)
		SO_2	2.28	(6)
3UFLARE63 (6)	Multi-Point Ground Flare	VOC	989.06	(6)
		NO_x	687.67	(6)
		CO	1051.73	(6)
		SO_2	0.04	(6)
PEXVCS (6)	Vent Control System	VOC	--	30.11
		NO_x	--	18.64
		CO	--	43.07
		SO_2	--	0.37
		PM	--	0.02
		PM_{10}	--	0.02
		$PM_{2.5}$	--	0.02
PEXTK1	Hexene Storage Tank	VOC	1.12	2.41
PEXANALZ	PEX Analyzer Catalytic Oxidizers	VOC	0.04	0.18
PEXFUGEM (5)	Fugitives	VOC	2.1	9.2
		NH_3	0.06	0.26
RUCT01	Cooling Tower	VOC (5)	42.08	2.27
		PM	1.32	5.76
		PM_{10}	0.82	3.59
		$PM_{2.5}$	<0.01	0.02

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
RLD01	Primary A/O Run Tank	VOC	<0.01	0.01
RLD02	Secondary A/O Run Tank	VOC	<0.01	0.02
4DDC04	Granule Filter Receiver (seed bed filter)	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3NDC01	Line 3 - Elutriator Cyclone Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4NDC01	Line 4 - Elutriator Cyclone Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PDC11	Line 3 - Prime Pellet Silo Vent 01	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PDC12	Line 3 - Prime Pellet Silo Vent 02	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3PDC13	Line 3 - Prime Pellet Silo Vent 03	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PDC14	Line 3 - Prime Pellet Silo Vent 04	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PDC15	Line 3 - Prime Pellet Silo Vent 05	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PDC16	Offspect - Pellet Silo Vent 06	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PDC11	Line 4 - Prime Pellet Silo Vent 01	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
4PDC12	Line 4 - Prime Pellet Silo Vent 02	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PDC13	Line 4 - Prime Pellet Silo Vent 03	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PDC14	Line 4 - Prime Pellet Silo Vent 04	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PDC15	Line 4 - Prime Pellet Silo Vent 05	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3MDC01	Line 3 - Pellet Surge Bin Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
4MDC01	Line 4 - Pellet Surge Bin Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3MFAN01	Line 3 - Pellet Dryer Vent-01	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3MFAN02	Line 3 - Pellet Dryer Vent-02	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4MFAN01	Line 4 - Pellet Dryer Vent-01	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4MFAN02	Line 4 - Pellet Dryer Vent-02	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3MBN01	Line 3 - Film Test Extruder Filter Receiver	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4MBN01	Line 4 - Film Test Extruder Filter Receiver	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LDC23	Finishing Building Vacuum System Dust Collector	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
34PKGBLDG	Combined Packaging Building Fugitives	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PFAN01	Bagging Line 3 Feed Hopper Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3PFAN21	Bagging Line 4 Feed Hopper Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PFAN41	Bagging Line 5 Feed Hopper Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PFAN01	Bagging Line 1 Feed Hopper Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PFAN21	Bagging Line 2 Feed Hopper Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3PFAN04	Bulk Loading Station 1 Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3PFAN05	Bulk Loading Station 2 Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PFAN04	Bulk Loading Station 3 Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4PFAN05	Bulk Loading Station 5 Vent	VOC	(8)	(8)
		PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LFAN04	Line 3 Additive Feed Hopper Blower Vent	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4LFAN04	Line 4 Additive Feed Hopper Blower Vent	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LDC06	Line 3 - Additive Drying Hopper Dust Collector	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
4LDC06	Line 4 - Additive Drying Hopper Dust Collector	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LB01	Line 3 - Vacuum Blower-01 Vent for Additive AB Transfer	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LB02	Line 4 - Vacuum Blower-02 Vent for Additive AB Transfer	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LB03	Line 3 - Vacuum Blower-03 Vent for Additive Transfer	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LB04 3LB05[1]	Lines 3/4 - Vacuum Blower-04 Vent for Additive Transfer	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4LB01	Line 4 - Vacuum Blower-01 Vent for Additive Transfer	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3LFAN01	Line 3 - Additive Dump Station Vent Dust Collector	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
4LFAN01	Line 4 - Additive Dump Station Vent Dust Collector	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3BFIL01	Line 3 - Cylinder Vent Filter-01	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3BFIL02	Line 3 - Cylinder Vent Filter-02	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3BFIL03	Line 3 - Cylinder Vent Filter-03	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4BFIL01	Line 4 - Cylinder Vent Filter-01	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4BFIL02	Line 4 - Cylinder Vent Filter-02	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4BFIL03	Line 4 - Cylinder Vent Filter-03	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
3CFIL04	Line 3 - Catalyst Hold Tank Filter-04	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3CFIL05	Line 3 - Catalyst Hold Tank Filter-05	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
3CFIL06	Line 3 - Catalyst Hold Tank Filter-06	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4CFIL04	Line 4 - Catalyst Hold Tank Filter-04	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4CFIL05	Line 4 - Catalyst Hold Tank Filter-05	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
4CFIL06	Line 4 - Catalyst Hold Tank Filter-06	PM	(9)	(9)
		PM_{10}	(10)	(10)
		$PM_{2.5}$	(11)	(11)
MISCVENTS (7)	Miscellaneous Vents	VOC (8)	17.42	13.83
		PM (9)	5.94	15.8
		PM_{10} (10)	1.01	2.51
		$PM_{2.5}$ (11)	0.86	1.88

Emission Sources - Maximum Allowable Emission Rates

Emission Point No. (1)	Source Name (2)	Air Contaminant Name (3)	Emission Rates	
			lbs/hour	TPY (4)
PEXMSS	Planned MSS	VOC	113.51	6.17
		NO_x	1.17	0.06
		CO	1.17	0.06
		PM	1.81	0.13
		PM_{10}	1.81	0.13
		$PM_{2.5}$	1.81	0.13
MAINDEG	Controlled Tank Degassing	VOC	1.08	0.02
		NO_x	8.16	0.10
		CO	0.63	0.01
		SO_2	< 0.01	< 0.01
		PM	0.02	< 0.01
		PM_{10}	< 0.01	< 0.01
		$PM_{2.5}$	< 0.01	< 0.01

(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
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) The Vent Control System (EPN: PEXVCS) contains annual emissions from the FTO System, Elevated Flare, and Multi-Point Ground Flare (EPNs 3UF61A/B/C, 3UFLARE62, and 3UFLARE63).

Emission Sources - Maximum Allowable Emission Rates

(7) Miscellaneous Vents (EPN: MISCVENTS) includes emissions from the Pellet Loadout Sources, Polyethylene Product Sources, Additive Sources, Catalyst Transfer Sources, Pellet Finishing Building, Pellet Packaging Building, and Pellet Bagging System.

(8) The listed emission rates are the cap for VOC emissions from the group of emission points in the polyethylene product transfer, storage, and loadout systems. The sum of emissions from all of the emission points in this group shall not exceed the emission rate listed for the group.

(9) The listed emission rates are the cap for total PM emissions from the group of emission points in the polyethlyene product, catalyst, and additive systems. The sum of emissions from all of the emission points in this group shall not exceed the emission rate listed for the group.

(10) The listed emission rates are the cap for PM_{10} emissions from the group of emission points in the polyethlyene product, catalyst, and additive systems. The sum of emissions from all of the emission points in this group shall not exceed the emission rate listed for the group.

(11) The listed emission rates are the cap for $PM_{2.5}$ emissions from the group of emission points in the polyethlyene product, catalyst, and additive systems. The sum of emissions from all of the emission points in this group shall not exceed the emission rate listed for the group.

Date: October 7, 2013

Construction Permit
Source Analysis & Technical Review

Company	**Exxon Mobil Corporation**	Permit Number	**103048**
City	**Mont Belvieu**	Project Number	**178209**
County	**Chambers**	Account Number	**CI-0009-P**
Project Type	**Initial**	Regulated Entity Number	**RN102501020**
Project Reviewer	**Mr. Kyle Virr, P.E.**	Customer Reference Number	**CN600123939**
Site Name	**Mont Belvieu Plastics Plant**		

Project Overview

ExxonMobil Chemical Company (ExxonMobil) owns and operates a polyethylene plant in Mont Belvieu, Chambers County known as the Mont Belvieu Plastics Plant (MBPP). The existing plant operates under Permit No. 19016 and various PBRs. This application requests the authorization of a new polyethylene unit (PEX) at the current plant.

Emission Summary

Air Contaminant	Current Allowable Emission Rates (tpy)	Proposed Allowable Emission Rates (tpy)	Change in Allowable Emission Rates (tpy)	Project Changes at Major Sources (Baseline Actual to Allowable)*
PM	0.00	23.79	23.79	23.79
PM_{10}	0.00	8.33	8.33	8.33
$PM_{2.5}$	0.00	4.13	4.13	4.13
VOC	0.00	70.72	70.72	20.71*
NO_x	0.00	22.66	22.66	17.36*
CO	0.00	54.27	54.27	54.27
SO_2	0.00	4.25	4.25	4.25
NH_3	0.00	1.43	1.43	1.43

*Netting was triggered for NO_x and VOC; however, ExxonMobil demonstrated that increases associated with this project were below the 25 ton major modification threshold. This includes emissions which are authorized through Permit No. 19016.

Compliance History Evaluation - 30 TAC Chapter 60 Rules

A compliance history report was reviewed on:	**August 5, 2013**
Compliance period:	**September 1, 2007 – August 31, 2012**
Site rating & classification:	**0.26 – Satisfactory**
Company rating & classification:	**11.91 – Satisfactory**
If the rating is 50<RATING<55, what was the outcome, if any, based on the findings in the formal report:	**NA**
Has the permit changed on the basis of the compliance history or rating?	**No**

Public Notice Information - 30 TAC Chapter 39 Rules

Rule Citation	Requirement	
39.403	Date Application Received:	**May 22, 2012**
	Date Administratively Complete:	**May 31, 2012**
	Small Business Source?	**No**
	Date Leg Letters mailed:	**May 31, 2012**
39.603	Date Published:	**June 24, 2012**
	Publication Name:	***The Baytown Sun***

Rule Citation	Requirement	
	Pollutants:	**Particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen oxides, sulfur dioxide, organic compounds, ammonia, and sulfuric acid (Note: No sulfuric acid emissions are being authorized by this permit; therefore, it is not included in the second public notice)**
	Date Affidavits/Copies Received:	**July 6, 2012**
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**June 22, 2012**
	Publication Name:	***El Perico***
	Date Affidavits/Copies Received:	**July 6, 2012**
	Date Certification of Sign Posting / Application Availability Received:	**May 23, 2013**
39.604	Public Comments Received?	**No**
	Hearing Requested?	**No**
	Meeting Request?	**No**
	Date Response to Comments sent to OCC:	**NA**
	Consideration of Comments:	**NA**
	Is 2nd Public Notice required?	**Yes**
39.419	Date 2nd Public Notice/Preliminary Decision Letter Mailed:	**August 27, 2013**
39.413	Date Cnty Judge, Mayor, and COG letters mailed:	**August 27, 2013**
	Date Federal Land Manager letter mailed:	**N/A**
39.605	Date affected states letter mailed:	**N/A**
39.603	Date Published:	**August 30, 2013**
	Publication Name:	***The Baytown Sun***
	Pollutants:	**Particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, carbon monoxide, nitrogen oxides, sulfur dioxide, organic compounds, ammonia, and sulfuric acid (Note: No sulfuric acid emissions are being authorized by this permit; therefore, it is not included in the second public notice)**
	Date Affidavits/Copies Received:	**September 30, 2013**
	Is bilingual notice required?	**Yes**
	Language:	**Spanish**
	Date Published:	**August 30, 2013**
	Publication Name:	***El Perico***
	Date Affidavits/Copies Received:	**September 30, 2013**

Rule Citation	Requirement	
	Date Certification of Sign Posting / Application Availability Received:	**October 3, 2013**
	Public Comments Received?	**No**
	Meeting Request?	**No**
	Hearing Request?	**No**
	Consideration of Comments:	**N/A**
39.421	Date RTC, Technical Review & Draft Permit Conditions sent to OCC:	**N/A**
	Request for Reconsideration Received?	**N/A**
	Final Action:	**N/A**
	Are letters Enclosed?	**N/A**

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:	**NO_x monitoring for boilers via CEMS, engineering calculations**
	Comments on emission verification:	**NA**
116.111(a)(2)(D)	Subject to NSPS?	**Yes**
	Subparts **A & DDD**	
116.111(a)(2)(E)	Subject to NESHAP?	**No**
	Subparts &	
116.111(a)(2)(F)	Subject to NESHAP (MACT) for source categories?	**Yes**
	Subparts **A FFFF & DDDDD**	
116.111(a)(2)(H)	**Nonattainment review applicability:** This project is located within the existing ExxonMobil Mont Belvieu Plastics Plant (an existing major source of NO_x and VOC) located in Chambers county which is classified as severe nonattainment for ozone. The proposed project triggered netting for VOC and NO_x. ExxonMobil provided a netting demonstration which included a future VOC emissions reduction project with a creditable decrease of 52.98 tons per year. This would give ExxonMobil a contemporaneous VOC increase of only 20.71 tons (less than the 25 ton threshold for a major modification). Contemporaneous increases for NO_x were demonstrated to be 17.36 tons (also less than the 25 ton major modification threshold) Special Condition No. 37 has been added to require ExxonMobil to realize the proposed VOC decrease prior to startup of this proposed expansion.	
116.111(a)(2)(I)	**PSD review applicability:** Emission increases of other criteria pollutants are below their respective Prevention of Significant Deterioration (PSD) significance levels; therefore, no contemporaneous emissions netting analysis is required. PSD review is not required.	
116.111(a)(2)(L)	Is Mass Emissions Cap and Trade applicable to the new or modified facilities?	
	If yes, did the proposed facility, group of facilities, or account obtain allowances to operate:	
116.140 - 141	Permit Fee: $ **75,000.00** Fee certification:	**R228494**

Title V Applicability - 30 TAC Chapter 122 Rules

Rule Citation	Requirement
122.10(13)	**Title V applicability:** The MBPP has Title V Permit Nos O-1446 and O-2276
122.602	**Periodic Monitoring (PM) applicability:** Periodic monitoring is performed through the following: Boilers – fuel flow, NH_3 slip, CEMs for NO_x.(note: CO CEMS not required since boilers are <100MMBtu each) RTO and FTOs– fuel flow and temperature. Flares – pilot flame, flow, heating value and composition of waste gas streams. Cooling towers – TDS, conductivity, recirculation rate, VOC. Floating roof storage tanks – tank seal inspections. Particulate control system 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 was submitted on December 27, 2012 requesting use of a sonic flare instead of a 60.18 compliant flare for RUFLARE63.) Special Condition Nos. 11 (elevated flare) and 12 (multi-point ground flare) require monitoring of flow rate/composition, pressure, and Btu content of the waste stream during operation. The boilers are required to be stack tested and will be equipped with a CEMs for NO_x. The RTO and FTOs are required to be stack tested and have exit temperature monitored per Special Condition Nos. 8 and 9.

Request for Comments

Received From	Program/Area Name	Reviewed By	Comments
Region:	**12**	**Chris Horton**	**Minor editorial comment**
City:	**Mont Belvieu**	**NA**	**No comments received**
County:	**Chambers**	**NA**	**No comments received**
Toxicology:		**Mr. Ross Jones**	**Impacts are acceptable**
Compliance:		**NA**	**No comments received**
Legal:		**NA**	**No comments received**
Comment resolution and/or unresolved issues:	**Comments from region were incorporated as requested**		

Process/Project Description

ExxonMobil is expanding their Mont Belvieu Plastics Plant by constructing a new polyethylene production unit (PEX). This is a stand-alone unit but will rely on existing MBPP utilities.

Process Description

The MBPP PEX Unit will manufacture plastics in two low pressure, gas phase fluidized bed reactors. Catalyst, monomer, co-monomer, and an inert gas are fed to the reactors. The polymer produced in the reactors is in the form of granules suspended by circulating gases. Product from the reactors goes through a series of polymer separation and drying steps, and is extruded into pellets. The pellets are transferred to storage silos and then shipped. The polymer produced in the reactors is in the form of tiny granules suspended by circulating gases used to remove heat. The polymer particles in the circulating gas form a fluidized bed in the reactor. Granular polyethylene is periodically removed through a series of tanks, along with entrained gas. Unreacted gases are removed from the gas/resin stream leaving the reactor by purge vessels which strip unreacted gas. The stripped gasses are routed through a vent collection system (VCS) controlled by three (3) identical flameless thermal oxidizers (FTO) (EPNs 3UF61A/B/C), an elevated flare (EPN 3UFLARE62), and a multi-point ground flare (EPN 3UFLARE63). The VCS ins comprised of two separate headers: a High Pressure (HP) Vent Header and a Low Pressure (LP) Vent Header. The VCS is designed to handle predominantly hydrocarbon streams in direct contact with the process (enclosed polymerization area) of the polyethylene unit.

The HP Vent Header is designed to receive high load, short duration vent streams, also referred to as "high volume, high concentration" (HVHC) from the reactors and the high capacity feed supply depressure. The primary control device for this stream is the multi-point ground flare. A computer control application ensures the multi-point ground flare is operated when the HP Vent Header meets the design conditions to achieve good combustion efficiency.

The LP Vent Header receives routine continuous vent streams form the process, as well as routine intermittent streams. These streams are referred to as low volume, low pressure (LVLP). The primary control devices for the LP Vent Header are the three FTOs operated in parallel. Installing three FTOs provides ExxonMobil the capacity to reliably control the expected routine vent stream flow within the LP Vent Header for VOC abatement. An automatic feed control system shall be provided to the FTOs to ensure optimal operation. When needed (FTO system capacity is reached, or one or more FTO is undergoing maintenance), a control valve will allow the utilization of the elevated flare for control of the LP Vent stream.

Throughout the process a number of process analyzers are positioned to measure various aspects of the process gas stream. Whenever possible, analyzer vent streams will be returned to the process stream, or routed to the VCS. Analyzers which have to be routed to atmosphere will be equipped with TRACErace™ technology or similar to control VOC emissions.

Unreacted gases are removed from the gas/resin stream by two-stage purge vessels that strip the unreacted gas from the reactor using an inert gas in the top section, while the bottom section may additionally use steam with inert gas to react trace reactants. Stripped gases are routed to the VCS for destruction. A small amount of residual hydrocarbon remains in the resin after purging. Liquid and dry additives from two additive tanks (EPNs RLD01 and RLD02) are then added to the granular product.

Granular resin is air conveyed from the purger area into tanks known as Feed Hoppers. Bag filters on the bins control particulate emissions. A portion of the remaining residual dissolved and chemically bound hydrocarbon gases evolve downstream of the purge vessel. An extruder uses the mechanical work of rotating screws to melt the plastic and push it through small holes into spaghetti-like strands. All residual hydrocarbons evolving during this portion of the process are routed to the RTO (EPN RUPK71) for destruction. The strands are cut with a series of rotating knives into small pieces called pellets, and stored in storage silos. The pellets are air conveyed from the product silos through a classification section and loaded into hopper cars for shipping. Bag filters and cyclones are utilized to minimize particulate emissions during this loading process.

MSS

MSS activities associated with a unit shutdown involve depressurizing the unit reactors and equipment to the PEX VCS and then degassing the process system to 10,000 ppmv. After the reactors and equipment have been degassed, the individual pieces of equipment and process vessels are opened to atmosphere so that cleaning, inspection, repair, or replacement can take place (EPN PEXMSS).

MSS activities associated with process equipment such as pumps, piping components, compressors, heat exchangers, vessels, furnaces, boilers, FTOs, and RTO include repairs, replacements, cleaning and inspections. When MSS on an individual piece of equipment is conducted, the equipment is isolated from the process, and then the pressure in the equipment is lowered to either a control device or to the atmosphere, depending on what is inside the equipment. After reducing pressure, any liquid or mixed phase material is removed to the maximum extent possible. Following liquid or mixed phase removal, if the partial pressure remaining in the equipment is 0.044 psia or greater at 68°F, then the equipment is degassed to a control device (EPN PEXMSS).

In order to perform maintenance of equipment, residual liquids are removed using a Vacuum Truck or Air Mover Truck. A Vacuum Truck is equipped with a blower which can be used to initially draw a vacuum of the container of the vacuum truck and then is turned off while liquid is drawn into the vacuum truck by the vacuum which was created by the blower

(EPN PEXMSS).

MSS activities associated with storage tanks with floating roofs include draining the tank, degassing the tank, cleaning the tank, inspecting the internals of the tank, and floating roof seals, making repairs or replacements as needed, and finally re-filling the tank. Since the VOC stored in PEXTK1 is 0.5 psia or greater, the degassing emissions will be controlled with an internal combustion engine, thermal oxidizer, flare, carbon adsorption system, main system liquid scrubbing system or closed loop refrigerated vapor recovery system (EPN MAINDEG)

Other Affected Sources in Other Permits

In addition to the new sources, PEX will rely on an existing oil/water separator currently authorized in NSR Permit No. 19016. An amendment to authorize increases associated with this project was submitted on August 8, 2013 and will be completed prior to the startup of PEX.

Permit Conditions

SC	Requirements
1	Boilerplate
2-4	Federal requirements
5	Polyethylene production limit
6	Fuel limitation
7	Boilerplate for boilers with BACT emission limitations
8	Boilerplate RTO
9	Boilerplate FTO
10	Boilerplate Elevated Flare
11	Boilerplate Multi-point ground flare
12	Boilerplate PM capture
13	Cooling tower TDS/Conductivity monitoring
14	Boilerplate Tanks
15-18	Boilerplate Fugitive
19-30	Boilerplate MSS
31	Boilerplate NO_x CEMS
32	Boilerplate Ammonia testing for SCR
33	Boilerplate Polyethylene Sampling
34	Boilerplate Stack testing
35	Recordkeeping
36	AMOC requirement for Multi-point ground flare
37	Emission reduction requirement prior to startup of PEX

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

Boilers

Two 98 MMBtu boilers 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 <0.01lb/MMBtu on a 12-month rolling average, and <0.025 lb/MMBtu on a rolling 24-hour average. CO emissions will be limited to 50 ppm at 3% O_2 on a 12-month rolling average. Ammonia slip (used in the SCR) will be limited to 10 ppm at 3% O_2. Formation of SO_2 will be limited by using only pipeline quality, low-sulfur (5 grains/dscf) fuel gas to fire the boilers. This meets current BACT.

RTO

The RTO is utilized to control residual emissions between the purger and the extruder. BACT for this process is normally no control. The RTO will achieve a destruction efficiency of 97% and maintain an outlet VOC concentration less than or equal to 10 ppmv on a 12-month rolling average. This exceeds current BACT.

RTO Downtime

During RTO maintenance, residual emissions between the purger and extruder will go uncontrolled. The RTO will have on-stream reliability of 97%. The worst case hourly VOC concentration controlled by the RTO is 100 ppmw.

Vent Collection System
The vent collection system (VCS) is comprised of two separate headers: a High Pressure (HP) Vent Header and a Low Pressure (LP) Vent Header. The VCS is designed to handle hydrocarbon streams in direct contact with the process. The HP Header is designed to receive high volume, high pressure streams from the reactors and the high capacity feed supply de-pressure. The primary control device for the HP Vent is the multi-point ground flare. The LP Vent receives routine continuous vent streams from the process as well as routine intermittent vent streams. These streams are low volume, low pressure streams which will be controlled primarily by the three FTOs operating in parallel. When needed (over the capacity of the FTOs), a control valve can be opened to utilize the elevated flare.

FTO
The 3 FTOs will achieve a destruction rate of 99.99%. This exceeds current BACT.

Elevated Flare
The elevated flare will achieve a destruction efficiency of 99% for hydrocarbons containing up to 3 carbon atoms, and 98% on molecules containing 4 or more carbon. This meets current BACT.

Multi-point Ground Flare
ExxonMobil is claiming a vendor guaranteed destruction efficiency of 99.5%. In order to validate this claim, Exxon will be required to test the proposed flare using a method which will have to be approved by the TCEQ. Due to the inability to field test a ground flare, ExxonMobil will be allowed to conduct testing at a test facility. The testing protocol is required by Special Condition No. 13 to be submitted no later than 90 days prior to the start of the test. Once the testing protocol has been approved, ExxonMobil will be required to complete the test no later than 180 days prior to start-up. If Exxon cannot prove the destruction rate through testing, the multi-point ground flare will not be authorized for use. Should the testing prove a 99.5% destruction efficiency, Exxon will be required to monitor the waste stream composition, pressure, and Btu with readings recorded every 6 minutes during operation. Exxon will be required to maintain a minimum pressure of 4 psia and minimum heating value of 800 Btu/scf on a rolling one-hour basis. Should these minimum standards not be met during operation of the flare, emissions will be calculated based on 98% destruction efficiency for all constituents in the waste stream. This is exceeds current BACT for multi-point ground flares.

A/O Run Tanks (Additive Tanks)
The A/O Run Tanks are <1,000 gallon storage vessels which will be operated with a nitrogen blanket. The tanks will only vent during material transfer. The liquid additives stored in the tanks will have a VOC vapor pressure of <0.0002 psia, and are therefore not typically considered to be air contaminants. The liquid additives are analogous to additives currently authorized in Permit No. 19016, so EPNs for the tanks were added for consistency. Combined emissions from the tanks are less than 0.03 tpy; therefore, no control is considered BACT.

Hexene Tank
The Hexene storage tank will be controlled by an internal floating roof with a mechanical shoe primary seal. This meets current BACT.

Analyzer Catalytic Oxidizers
The 35 analyzers which are unable to vent back to the process or into the VCS will achieve a 98% DRE utilizing TRACErace™ or similar technology. These are electric control devices; therefore, there are no products of combustion associated with VOC destruction. This is considered BACT for this type of vapor oxidizer.

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 <0.001%. This meets current BACT for cooling towers.

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.

MSS
Unit Shutdown and Routine Equipment MSS
Process equipment will be depressurized to a control device or a controlled recovery system prior to venting to atmosphere, degassing or draining liquid. Equipment that only contains material that is liquid with VOC partial pressure less than 0.044 psi at 68°F will be opened to atmosphere and drained. In the case of mixed-phase material, the cleared material will be routed to a knockout drum or equivalent to allow for managed initial phase separation. If VOC partial pressure is greater than 0.044 psi at 68°F, any vents will be routed to a control device or controlled recovery system. Control will remain in place until degassing has been completed or the system is no longer vented to atmosphere. All liquids from process equipment or storage vessels will 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 at 68°F will be drained into a closed vessel or closed liquid recovery system unless prevented by the physical configuration of the equipment. If it is necessary to drain liquid into an open pan or sump, the liquid must be covered or transferred to a covered vessel within one hour of draining. For VOC partial pressures greater than 0.044 psi at 68°F, facilities will be degassed using good engineering practices 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. Venting to atmosphere will be minimized to the maximum extent possible. This is BACT for MSS activities.

VAC Truck and Air Mover Truck MSS
Prior to use of any Vacuum or air mover truck, any liquid in the truck will be identified. If vacuum pumps or blowers are operated when liquid is in or being transferred to the truck and the VOC partial pressure of the liquid being transferred is greater than 0.1 psi, the vacuum/blower exhaust will be routed to control. If the hose end of the intake line cannot be submerged in the liquid being collected, the fill line will be equipped with a "duckbill" or equivalent attachment. This is BACT for air mover trucks.

Tank Degass
Tank roofs will only be landed for changes of tank service or tank inspection/maintenance. Tank roof landings include all operations when the tank floating roof is on its supporting legs. The tank will not be opened except as necessary to set up for degassing and cleaning. Any gas or vapor removed from the vapor space under the roof will be routed to a control device or a controlled recovery system until VOC concentration is less than 10,000 ppmv or 10% of the LEL. A volume of purge gas equivalent to twice the volume of vapor space under the floating roof will be passed through control before the vent stream may be sampled to verify acceptable VOC concentration. Degassing will be performed until there is no standing liquid in the tank or the VOC partial pressure is less than 0.15 psia. Tanks will be refilled as rapidly as practicable until the roo is off its legs. Only one tank with a landed floating roof can be filled at any time.

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:			

Summary of Modeling Results
ExxonMobil modeled off-property impacts of criteria pollutants and speciated VOCs using AERMOD. A modeling audit was performed by the TCEQ Air Dispersion Modeling Team (ADMT). A memo issued by the ADMT on June 20, 2013 declared that the modeling analysis was acceptable for all review types and pollutants.

A summary of NAAQS impacts for the projects follows:

Pollutant	Averaging Time	GLC_{max} (µg/m³)	De Minimis (µg/m³)
SO_2	1-hr	7.6	7.8
SO_2	3-hr	4	25
SO_2	24-hr	2	5
SO_2	Annual	0.1	1
PM_{10}	24-hr	3	5
$PM_{2.5}$	24-hr	2.4	1.2
$PM_{2.5}$	Annual	0.15	0.3
NO_2	1-hr	19	7.5
NO_2	Annual	0.1	1
CO	1-hr	86	2000
CO	Annual	47	500

Sitewide $PM_{2.5}$, and NO_2 were further evaluated including background data from the EPA AIRS monitors 482010617 (NO_x) located at 4727 Wallisville Road, Baytown, Harris County and 482010058 ($PM_{2.5}$) located at 7210 ½ Bayway Drive, Baytown, Harris County against the 24-hr standard and 1-hr standard as appropriate, 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	21	30	35
NO_2	1-hr	105	79	184	188

Fourteen compounds were reviewed 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: additives, alkenes, ammonia, butane, butane, catalysts, ethys, ethyl hexanes, hexane (health), pentanes, tetrahydrofuran, and toluene.

The following chemicals had exceedances and were further evaluated by for off-property health effects by way of site wide modeling: Hexene and polyethylene, the predicted off-property concentrations are less than the associated ESL, so no further review is required.

The following compounds were reviewed by Mr. Ross E. Jones in the Toxicology Division under the Tier III guidelines. Impacts were found to be acceptable.

Pollutant & CAS#	Averaging Time	Hours > 1 X ESL GLC_{ni}	Hours > 2 X ESL GLC_{max}
Polyethylene	1-hr	5	3
Hexene	1-hr	8	8

Permit Concurrence and Related Authorization Actions

Is the applicant in agreement with special conditions?	**Yes**
Company representative(s):	**Mr. Benjamin Hurst**
Contacted Via:	**Phone**
Date of contact:	**8/23/2013**
Other permit(s) or permits by rule affected by this action:	**NA**
List permit and/or PBR number(s) and actions required or taken:	**NA**

Kristi Mills-Jurock 10/03/13
Project Reviewer Date
for Kyle Virr

10/3/13
Team Leader/Section Manager/Backup Date

Attachment 2

- EPA Statement of Basis for Permit PSD-TX-103048-GHG

Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the ExxonMobil Chemical Company, Mont Belvieu Plastics Plant

Permit Number: PSD-TX-103048-GHG

July 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) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for greenhouse gas (GHG) emissions for a proposed construction project at its Mont Belvieu Plastics Plant (MBPP). 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 Mont Belvieu Plastics Plant would involve construction of a new polyethylene unit at the existing facility. ExxonMobil would be adding the following emission units: three flameless thermal oxidizers, a regenerative thermal oxidizer, an elevated flare, a multi-point ground flare, two boilers, analyzer catalytic oxidizers, and fugitives. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of GHG emission sources at the MBPP.

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 initially 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 initial 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
Mont Belvieu Plastics Plant
P.O. Box 1653
Baytown, TX 77580-1653

Physical Address:
13330 Hatcherville Road
Mont Belvieu, TX 77580

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, Mont Belvieu Plastics Plant is located in Chambers County, Texas. The geographic coordinates for this facility are as follows:

Latitude: 29° 52' 43" North
Longitude: - 94° 55' 12" West

Chambers 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 Breton National Wildlife Refuge.

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

Figure 1. ExxonMobil Chemical Company, Mont Belvieu Plastics Plant Location

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

EPA concludes that ExxonMobil's application is subject to PSD review for the pollutant GHGs, because the project would lead to a net emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (ExxonMobil calculates CO_2e emissions of 138,216 tpy). 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.

The applicant represents that the proposed project is not a major stationary source for non-GHG pollutants. The applicant also represents that the increases in non-GHG pollutants will not be authorized (and/or have the potential) to exceed the "significant" emissions rates at 40 CFR § 52.21(b)(23). At this time, TCEQ, as the permitting authority for regulated NSR pollutants other than GHGs, has not issued the permit amendment for non-GHG pollutants; limits below the rates identified in 52.21(b)(23) must be in place prior to construction for this applicability analysis and for the source's authorization to construct to be valid.[1]

EPA Region 6 takes into account the policies and practices reflected in the EPA document "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with recommendations 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 of 40 CFR 52.21 (o) and (p), respectively. Instead, EPA has determined that compliance with the selected BACT is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules, with respect to emissions of GHGs. The applicant has, however, submitted an analysis to evaluate the additional impacts of the non-GHG pollutants, as it may otherwise apply to the project.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ExxonMobil to construct a new polyethylene production unit. The new unit will produce polyethylene in low pressure, gas-phase fluidized bed reactors. The proposed facilities include feed purification, polymerization, resin degassing, additives addition, pelletization, blending, storage and shipping consisting of the following emission units: three flameless thermal oxidizers, a regenerative thermal oxidizer, an elevated flare, a multi-point ground flare, two boilers, analyzer catalytic oxidizers, and fugitives.

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

The new polyethylene production unit increases the plant capacity adding approximately 1.75 million tons per year of polyethylene production.

More specifically, transition metal halides and metal alkyls are impregnated onto catalyst support particles similar to fine sand. After manufacture, the catalyst is measured and conveyed into the reactor with an inert gas. The catalyst initiates the reaction of monomer (ethylene) and co-monomers (butene, hexene) in the reactor. Potential trace components that may impact the polymerization process are removed from reactor feed streams in the purification area. This purification process takes place in packed bed vessels. The reaction of gases involves polymerization, which is the linking or bonding of molecules to produce the polymer. Non-reactive components are used to control catalyst activity and/or act as a heat removal medium. In certain products, a metal alkyl is injected in small amounts to scavenge catalyst impurities and act as a co-catalyst. The polymer produced in the reactor is in the form of granules suspended by circulating gases used to remove heat. The polymer particles in the circulating gas form a fluidized bed in the reactor. Granular polyethylene is periodically removed through a series of tanks, along with entrained gas.

Unreacted gases are removed from the gas/resin stream leaving the reactor by degassing purge vessels that strip the gas from polyethylene product using an inert gas. Stripped gases are recovered with a vent recovery system. Some of the unrecovered residual hydrocarbon lean gases are routed through a vent collection system for destruction in a flameless thermal oxidizer (FTO) system, an elevated flare, and/or the multi-point ground flare. A very small amount of residual hydrocarbon remains in the resin after purging.

Granular resin is air-conveyed from the purger area into silos (feed bins). Bag filters on the bins control particulate emissions. The extruder uses mechanical work to melt the plastic and push it through a die-plate containing small holes. The plastic extrudes through these holes into spaghetti-like strands. Most of the residual hydrocarbon that may evolve from purged resin, during conveying is routed to a regenerative thermal oxidizer (RTO). The strands are cut with a series of rotating knives into small pieces known as pellets. These pellets are then conveyed into product silos. The material is air-conveyed from the product silos to loadout. The product silos and load out stations are equipped with bag filters and cyclones to minimize the emission of particles to the atmosphere.

A description of the emission points is provided below:

<u>Regenerative Thermal Oxidizer (EPN: RUPK71)</u>

The regenerative thermal oxidizer will control the residual VOC emissions from the powder hopper bag filter, polyethylene conveying system air vents, and extruder feed vents, all of which typically have less than 130 ppmv of residual hydrocarbons. Supplemental fuel is added to the regenerative thermal oxidizer to ensure sufficient chamber temperature. No supplemental oxygen is necessary to enhance the combustion process.

Vent Collection System Consisting of Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C), Assisted Flare (EPN: 3UFLARE62), and Multi-point Ground Flare System (EPN: 3UFLARE63)

Multiple hydrocarbon vent streams from routine continuous (e.g., purger vent) and intermittent (e.g., feed purification bed regeneration, startup/shutdown, etc.) operations will be collected by a Vent Collection System. The Vent Collection System is comprised of two separate headers: a High Pressure (HP) Vent Header and a Low Pressure (LP) Vent Header.

High Pressure Vent Header

The HP Vent Header is designed to receive high load, short duration vent streams, also referred to as "high volume, high pressure" (HVHP) vent stream from the reactors and the high capacity feed supply depressure. The primary control device that will control VOC emissions on the HP Vent Header is a multi-point ground flare system (EPN: 3UFLARE63).

Multi-point Ground Flare System (EPN: 3UFLARE63)

The multi-point ground flare system uses an array of high pressure burners to produce short, highly efficient flames. Pressure assisted burners utilize the flare gas pressure to ensure high exit velocity at the burner exit. The high velocity produces the energy required to promote high air entrainment and mixing in the combustion zone. This entrainment/mixing energy in the combustion zone is the key to producing an efficient, smokeless flame. The multi-point ground flare has a minimum flare combustion efficiency of 99.5% for hydrocarbons containing three or less carbon molecules (e.g. methane).

Low Pressure Vent Header

The LP Vent Header will receive routine continuous vent streams from the process, as well as routine intermittent vent streams. The streams are also referred to as "low volume, low pressure" (LVLP) streams. A high VOC control efficiency will be achieved through the use of three flameless thermal oxidizers (FTOs) with an elevated flare serving as a secondary control device. The LP Vent Header will be equipped with on-line analyzers to provide real time measurement of the heat content and speciation of vent streams. This will allow for supplemental natural gas injection, if required, to maintain minimum heating value content in the vent gas.

Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C)

The flameless thermal oxidizers (FTOs) will be used to control emissions from unrecovered waste gas from the process. The patented technology of the proposed FTO consists of a packed-bed, refractory-lined reactor filled with porous, inert ceramic media. Organic compounds are oxidized into CO_2 and water vapor. At startup, the ceramic packing in the oxidizer vessel is heated to the required operating temperature with a natural gas fired burner. The FTOs have a destruction and removal efficiency (DRE) of 99.99% for hydrocarbons containing three or less carbon molecules (e.g. methane).

Elevated Flare (EPN: 3UFLARE62)

The elevated flare provides additional capability to control all vent streams during normal operation of the low pressure (LP) vent header and is the last control disposition within the vent collection system. This flare has a destruction and removal efficiency (DRE) of 99% for hydrocarbons with three or less carbon atoms and this flare requires supplemental natural gas during periods of low heating value content. Air blowers or steam assist will be provided as part of the elevated flare system.

Boilers (EPNs: RUPK31 and RUPK32)

Two boilers each with a design firing capacity of 98 MMBtu/hr (HHV basis) will be used to produce steam for the proposed project. The boilers will fire pipeline quality natural gas.

Analyzer Catalytic Oxidizers (EPN: PEXANALZ)

The proposed project design contains up to 35 analyzer catalytic oxidizers distributed throughout the process equipment. There will be up to 12 feed analyzers and up to 23 process analyzers that might incorporate the catalytic oxidizers. Where applicable, analyzer vent streams are either returned to process or vented to the Vent Collection System. Analyzer streams with very low hydrocarbon content that cannot be returned to process or vented to the Vent Collection System or atmosphere will contain TRACErase™ technology or similar technology to destroy the VOC emissions prior to release to the atmosphere. TRACErase™ technology uses a catalytic combustion process to oxidize vented streams. The analyzer catalytic oxidizers utilize a continuous heat source (catalytic converter) to allow effective oxidation of source streams. The analyzer catalytic oxidizers have a destruction and removal efficiency (DRE) of 98% for hydrocarbons.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted in accordance with 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., flameless thermal oxidizers, regenerative thermal oxidizer, ground flare, elevated flare, and boilers). 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:

- Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C)
- Regenerative Thermal Oxidizer (EPN: RUPK71)
- Multi-point Ground Flare System (EPN: 3UFLARE63)
- Assisted Elevated Flare (EPN: 3UFLARE62)
- Boilers (EPNs: RUPK31 and RUPK32)
- Equipment Fugitives (EPN: PEXFUGEM)
- Analyzer Catalytic Oxidizers (EPN: PEXANALZ)

IX. Vent Collection System Consisting of Flameless Thermal Oxidizers (EPNs: 3UF61A, 3UF61B, and 3UF61C), Assisted Elevated Flare (EPN: 3UFLARE62), and Multi-point Ground Flare System (EPN: 3UFLARE63) BACT Analysis

The purpose of the vent collection system is to segregate and control VOC-containing vent streams from the process to the appropriate control device to maximize VOC destruction. Due to the integration of computer control applications that manage these control devices and operation of the vent collection system, this BACT analysis focuses on the combined vent collection system as a collective emission source. The vent collection system will consist of a low pressure (LP) vent header and a high pressure (HP) vent header. The LP vent header will route streams to the flameless thermal oxidizers (FTOs) and the elevated flare. The HP vent header will route streams to the multipoint ground flare. The elevated flare will provide backup to the FTOs during periods of excess venting to the LP vent header, as well as backup to the HP vent header when the heat value, header pressure, and/or the flow rate drops below operational or compliance targets. The primary emissions will be CO_2, with some CH_4 from any incomplete combustion, and N_2O will be emitted in trace quantities due to partial oxidation of nitrogen. The FTOs will have a hydrocarbon destruction and removal efficiency (DRE) of 99.99%. The multi-point ground flare has a minimum hydrocarbon DRE of 99.5%. For the purposes of this analysis of GHG emissions, the elevated flare is conservatively presumed to have a hydrocarbon DRE of 98% for the hydrocarbons being combusted.

As part of the PSD review, ExxonMobil provides in the GHG permit application a 5-step top-down BACT analysis for the FTOs, elevated flare, and multi-point ground flare that are part of the vent collection system. EPA has reviewed ExxonMobil's BACT analysis for these emission units, 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)* – CCS is an available add-on control technology that is applicable for all of the site's affected combustion units.
- *Use of Low Carbon Assist Gas* – The proposed control devices combust natural gas to maintain proper control device temperature and destruction efficiency. Natural gas is the lowest carbon fuel available for the proposed project.
- *Good Operating and Maintenance Practices* – Good combustion practices include appropriate maintenance of equipment, operation at the designed temperature and oxygen concentration for the FTOs, operation based on designed velocity and heating value for the elevated flare, and operation based on recommended design pressure and heating value for the multi-point ground flare.
- *Staged Operation* – The proposed project will install a vent collection system with staged operation. By segregating these low and high volume streams into different control device dispositions, the proposed project will optimize the amount of assist gas (natural gas) and air/steam to hydrocarbon ratio required for good combustion. This will minimize the amount of CO_2 generated by the destruction of vent streams.
- *Energy Efficient Design* –Use of a variable flow air blower with a computer control application can control the excess oxygen available during combustion.
- *Vent Gas Recovery (VGR)* – Recover routine continuous vent streams prior to combustion in a control device and utilize the heat content to reduce natural gas consumption at the boilers thereby avoiding GHG emissions.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[2]

Carbon Capture and Storage

CCS 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)."[3] 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). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for vent control applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed facility; the third approach, post-combustion capture, is applicable to the FTOs, flares, and other combustion units covered by this permit application.

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 are multiple mature oil and gas fields that could be suitable targets for enhanced oil recovery projects or that could have suitable brine formations either below or above known production zones, that could serve as storage reservoirs. These sites, however, would require intensive evaluation and would very likely require substantial remedial work to provide the high degree of site and formation integrity necessary for secure storage. There is a large body

[2] 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.
[3]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)

of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[4]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Low-Carbon Assist Gas
- Good Operating and Maintenance Practices
- Staged Operation
- Energy Efficient Design
- Vent Gas Recovery (VGR)

CCS is capable of achieving 90% reduction of generated CO_2 emissions and thus is considered to be the most effective control method. Use of low-carbon assist gas, energy efficient design, staged operation, vent gas recovery, and good combustion and maintenance practices are all considered effective, can be used in tandem, and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only (and is not especially meaningful, given that these technologies are not mutually exclusive).

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 Storage

ExxonMobil developed and submitted an evaluation of CCS costs for consideration in step 4 of the BACT process. In their evaluation, the majority of the cost for CCS was attributed to the capture and compression facilities that would be required to be constructed and operated. The applicant has reliably shown that carbon capture and compression facilities would include CO_2 compressor and intercoolers (estimated cost of $32.9 million), amine absorber system (estimated cost of $61.3 million), CO_2 regeneration and purification system (estimated cost of $21.5 million), and blower, piping, and ducting (estimated cost of $14.8 million). Additional utilities would need to be constructed as well. The additional utilities would require construction of a new utility plant – consisting of a boiler with boiler feed water treatment and a blower – estimated to cost $27.7 million. The construction of a new cooling tower, utility header, and piping would cost an estimated $50.1 million. The cost for the new pipeline would be $18.3 million, based on an 8-inch diameter pipeline going 20 miles (distance to nearest CO2 pipeline stem). The total capital cost for carbon capture is estimated to be $208,300,000, which includes

[4] 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

compression equipment, amine treating, regeneration and purification system, and additional utilities. The total annual cost of CCS capital and operating expenses would be $50,800,000 per year. The addition of CCS would increase the project capital costs by more than 25%. According to the applicant, such an increase in capital cost would make the project economically unviable. EPA Region 6 reviewed ExxonMobil's CCS cost estimate and agrees that it adequately approximates the cost of a CCS control for this project and demonstrates that those costs are excessive in relation to the overall cost of the proposed project. As noted below, these same reasons for rejecting CCS apply equally with respect to the other emission areas at ExxonMobil.

In addition to maintaining that CCS would be economically infeasible for this project, ExxonMobil also asserts that CCS can also be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. According to the applicant, implementation of CCS would increase emissions of NOx, CO, VOC, PM_{10}, and SO_2 by as much as 21% from the additional utilities and energy demands that would be required to operate the CCS system. The increase in these criteria pollutants, according to the applicant, 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.

EPA notes that where GHG control strategies affect emissions of other regulated pollutants, trade-offs in selecting GHG pollution controls can be legitimately taken into account. See PSD Permitting Guidance at pp. 40-42. Here, the 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. Many of the devices whose carbon emissions have triggered PSD permitting for GHGs (the thermal oxidizers and flares, for example) are pollution control measures to control emissions of ozone precursors. Thus, there is special sensitivity about employing control measures that would result in emission increases of ozone precursors. EPA reviewed ExxonMobil's cost analysis and the estimated pollutant increases that would result from the implementation of CCS, and concludes that CCS can be eliminated as BACT for this project due to the cost increase to the project. It is not necessary, therefore, to also reject CCS based on the projected collateral emission increases of ozone precursors in an ozone non-attainment area, but EPA notes that the applicant's concerns are legitimate factors for consideration.

Low-Carbon Assist Gas

The use of natural gas as an assist gas is inherent in the design and operation of the FTOs and flares at MBPP. There are no negative economic, environmental, or energy impacts associated with this option.

Good Operating and Maintenance Practices

Good operation and maintenance practices for the FTOs and flares 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. There are no negative economic, environmental, or energy impacts associated with this option.

Staged Operation

There are no negative economic, environmental, or energy impacts associated with this option.

Energy Efficient Design

Energy efficient design will be incorporated into the vent collection system, specifically, utilization of air blowers with computerized control to control the excess oxygen based on the incoming feed to the FTOs. There are no negative economic, environmental, or energy impacts associated with this option.

Vent Gas Recovery (VGR)

The proposed project incorporates a state-of-the art technology to recover unreacted gases from the polyethylene reactor system to minimize air emissions. The vent gas recovery system is inherent in the design and operation of the proposed polyethylene plant, and includes recovery compressors, refrigeration systems, heat exchangers, pumps and vessels, to return unreacted hydrocarbon liquids back to the process. Specifically vent gases will be filtered by a compressor intake filter, cooled in a pre-cooler, compressed in a multi-stage recovery compressor with an inter-stage cooler, and then condensed using ethylene refrigeration in order to recover and return unreacted hydrocarbon liquids back to the process. The proposed polyethylene plant includes additional recovery technologies such as a reactor vent column and two-staged membrane unit to achieve incremental increases in gas recovery. The reactor vent column is used to control nitrogen concentration of reactor content, with a small vent to the flare. The vent column scrubs vent gases through a packed column using recovered liquids to 'wash' and extract hydrocarbon present in the vent stream to the flare for routing back to the process. The two-staged membrane unit is a separation system to further enhance recovery of lighter molecules by separating a low pressure hydrocarbon rich stream from a high pressure nitrogen rich stream in the first membrane module. The hydrocarbon stream is recycled back into the process. The high pressure nitrogen stream goes to the second stage membrane module to purify the nitrogen for use in the process. Finally, after cycling through the vent gas recovery system, and two-staged membrane system, unrecovered vapor, as the low pressure permeate from the second module is sent to the control device system. This system will avoid the generation of approximately 810,000 tons CO_2e/yr. Vent gas recovery will be utilized at the proposed facility; however, there will be a small amount of vent gas recovery system "off-gas" that will not be able to be recovered further.

The vent gas that ExxonMobil is unable to collect by the vent gas recovery system, vent column, and two-staged membrane system are routed to another vent collection system for destruction in an FTO, elevated flare, or the multi-point ground flare. ExxonMobil explored the possibility of routing the vent gas recovery system "off-gas" to the boilers as supplemental fuel. ExxonMobil determined that a compression system would be needed with a total capacity to process up to 1,800 pounds per hour of "off-gas", which is equivalent to 1,000 pounds per hour of natural gas. This flow rate is based on the estimated amount of vent gas the boilers could reliably fire in place of natural gas. The use of the "off-gas" as fuel could result in 9,000 tons per year of CO_2e avoided. ExxonMobil provided a cost analysis for such a system to utilize the "off-gas" as a fuel in the boilers.[5] ExxonMobil has demonstrated that the costs to recover the "off-gas" as a fuel are disproportionately high; therefore, using the "off-gas" as a fuel in the boilers is eliminated as a control option.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the vent collection system:

- *Low Carbon Assist Gas* – Pipeline quality natural gas, or a fuel with a lower carbon content than pipeline quality natural gas, as supplemental fuel to the FTOs and flares.
- *Good Operation and Maintenance Practices* –
  - *LP Vent Header* –
    - Monitor the composition and heat value of the vent gas contained in the LP Vent Header through online analyzers and record the heating value.
  - *FTOs* –
    - Monitor and record the vent gas flow to the FTO through a flow monitoring system;
    - Monitor the excess oxygen at the exhaust stack of the FTOs and maintain excess oxygen above the minimum demonstrated for the designated DRE during the performance test;
    - Monitor the temperature of the FTOs and maintain the temperature above the minimum demonstrated temperature or manufacturer recommended temperature;

[5] See pages 4-11 through 4-12 of the revised application submitted March 2013 and email from Benjamin Hurst to Jeffrey Robinson dated May 23, 2013. The revised application is available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-mont-belvieu-revisedapp03082013.pdf
The email is available at http://www.epa.gov/earth1r6/6pd/air/pd-r/ghg/exxonmobil-mont-belvieu-vent-gas-recovery.pdf

        - Visually inspect burners during routine preventative maintenance outages and prior to start-up to ensure proper operation.
    - *Elevated Flare* –
        - Monitor and record the flow to the elevated flare through a flow monitoring system;
        - 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 flow;
        - Monitor and record the composition and heating value of the vent gas (including assist gas) within the LP Vent Header;
        - Monitor pilots for presence of flame.
    - *Multi-point Ground Flare* –
        - Monitor the pressure 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 may be implemented after approval by EPA;
        - Monitor and record the pressure of the HP Vent Header;
        - Monitor and record the composition of the vent gas within the HP Vent Header;
        - Monitor and maintain a minimum heating value of 800 Btu/scf of the off gas including assist 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 may be implemented after approval by EPA;
        - Monitor pilots for presence of flame.
- *Staged Flaring* – A staged flare system will be utilized.
    - *Operation of the control applications to manage disposition of the vent streams among the Vent Headers and the control devices.*
    - *Manual overrides and/or manual bypasses will be employed only during unexpected and unplanned failure of the computer control system to properly operate.*
- *Energy Efficient Design* –
    - *Use FTO variable flow air blowers with computer control application to control the excess oxygen on the incoming feed.*
    - *Use computer control application to minimize assist gas firing in the FTO.*
    - *Use variable assist at elevated flare with computer control application.*
- *Vent Gas Recovery* –
    - *Vent gases will be filtered by a compressor intake filter, cooled in a pre-cooler, compressed in a multi-stage recovery compressor with an inter-stage cooler, and*

- *then condensed using ethylene refrigeration in order to recover and return unreacted hydrocarbon liquids back to the process.*
- *A reactor vent column will be utilized to scrub vent gases using recovered liquids to extract hydrocarbons in the vent stream for routing back into the process.*
- *A two-stage membrane separation system will be utilized to recover a low pressure hydrocarbon stream from a high pressure nitrogen stream. The hydrocarbon stream is recycled back to the process.*

BACT Limits and Compliance:

EPA is proposing that ExxonMobil will monitor and record the following parameters for the multi-point ground flare system, flameless thermal oxidizer system, and the assisted elevated flare system to demonstrate continuous compliance with the vent collection system operating specifications:

- Continuously monitor and record the pressure of the HP vent header,
- Continuously monitor and record the vent gas flow to the elevated flare and FTOs through a flow monitoring system,
- Continuously monitor and record the excess oxygen at the exhaust stack of the FTOs and maintain excess oxygen above the minimum demonstrated during the initial performance testing.
- Continuously monitor and record the temperature of the FTOs and maintain the temperature above the minimum demonstrated during the initial performance testing.
- Continuously monitor flare pilots for continuous presence of flame,
- Continuously monitor the composition and heating value of the waste gas combusted in the flare through online analyzers located on the LP vent header and the HP vent header, and record the heating value of the flare system header,
- Continuously monitor the pressure 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 shall be implemented following EPA approval,
- 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, and
- Monitor and maintain a minimum heating value of 800 Btu/scf of the waste gas including assist 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 through an equivalency determination to achieve the same level of combustion efficiency, then this lower limit shall be implemented following approval by EPA.

Using these operating practices above will result in an emission limit for the vent collection system of 104,413 tpy CO_2e. This emission limit is a reduced emissions cap for the FTOs, elevated flare, and the multi-point ground flare combined. The FTOs will have a combined emission limit of 91,660 tpy of CO_2, the elevated flare will have an emission limit of 6,304 tpy CO_2, and the multi-point ground flare will have an emission limit of 7,735 tpy of CO_2.

ExxonMobil will calculate the CO_2 emissions from the flares (EPNs: 3UFLARE62 and 3UFLARE63) using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, or site specific fuel analysis for natural gas, and the site specific fuel analysis for waste gas (see Tables A-2, and A-4 of the GHG permit application). The equation for estimating CO_2 emissions from the flares is equation Y-1a, as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.98 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

CO_2 = Annual CO_2 emissions for a specific fuel type (short tons/year).

0.98 = Assumed combustion efficiency of the elevated flare (use 0.995 for the multi-point ground 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 emission limits, for the flares (EPNs: 3UFLARE62 and 3UFLARE63), associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98 Subpart C, Table C-2 or site specific analysis of natural gas, site specific analysis of waste gas, and the actual heat input (HHV) and using equations Y-4 and Y-5 respectively, from 40 CFR Part 98 Subpart Y.

The FTOs (EPNs: 3UF61A, 3UF61B, and 3UF61C) will have a combined emission limit of 91,660 tpy of CO_2. ExxonMobil will demonstrate compliance with the CO_2 emission limit for the FTOs using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1 or site specific fuel analysis for natural gas, and the site specific fuel analysis for waste gas (see Table A-1 of the GHG permit application). The equation for estimating CO_2 emissions for the FTOs is equation C-5, 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 emission limits associated with CH_4 and N_2O, for the FTOs, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 or site specific analysis for natural gas, site specific analysis of waste gas, and the actual heat input (HHV) using equation C-8 from 40 CFR Part 98 Subpart C.

To calculate the CO_2e emissions, the 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

X. Regenerative Thermal Oxidizer (EPN: RUPK71) BACT Analysis

The regenerative thermal oxidizer (RTO) is a control device that will be installed to meet BACT for another PSD pollutant (volatile organic compounds (VOC)). The RTO will control criteria pollutant emissions from the powder hopper bag filter, conveying are vents, and extruder feed vents. These vents typically all emit less than 130 ppmv of residual hydrocarbons. The RTO will have a hydrocarbon destruction and removal efficiency (DRE) of 99% or less than 2 ppmv methane in the outlet concentration.

Step 1 – Identification of Potential Control Technologies

- *Use of Low Carbon Assist Gas* – The proposed RTO combusts natural gas to maintain proper control device temperature and destruction efficiency. Natural gas is the lowest carbon gas available for the proposed project.
- *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
- *Energy Efficient Design* – Energy efficiency is inherent in the operation of an RTO. Specific technologies include feed preheating, insulation, and optimization of the fuel/air mixture.
- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites affected combustion units.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Low Carbon Assist Gas;
- Use of Good Operating and Maintenance Practices; and
- Energy Efficient Design.

All options identified for controlling GHG emissions from the RTO are considered effective and have a range of efficiency improvements which cannot be directly quantified, and can all be used together. Therefore, a ranking is unnecessary.

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

Although all fossil fuels contain carbon, the natural gas fired in the proposed RTO is a low carbon assist gas. The use of low carbon assist gas and good operating and maintenance practices are inherent in the design and operation of the RTO at MBPP. Energy efficient designs will be incorporated, specifically, feed preheat, insulation, and improved process control.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizer:

- Use of Low Carbon Assist Gas - Only pipeline quality natural gas will be utilized in the RTO burners.
- Good Operating and Maintenance Practices - ExxonMobil will ensure good operation and maintenance practices through the use of a flow monitoring system to record the vent gas flow and the supplemental fuel gas flow. The burners will be inspected, at a minimum, annually to ensure proper performance.
- Energy Efficient Design - To ensure efficient operation, ExxonMobil will monitor the combustion chamber temperature of the RTO and maintain it at or above 1,400°F. The RTO will also utilize the following technologies:
    - Feed Preheat - Hot purified air releases thermal energy as it passes through a media bed (typically ceramic) in the outlet flow direction. The media bed is then used to preheat inlet gases. Altering airflow direction into the media beds maximizes energy recovery.
    - Insulation of the RTO to retain heat within the unit, thereby reducing firing demand.

Using these operating practices will result in an annual emission limit of 2,552 tpy CO_2e. Compliance shall be determined by the monthly calculation of GHG emissions using equation C-5, 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 emission limits associated with CH_4 and N_2O, for the RTOs, are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 or site specific analysis for natural gas, site specific analysis of waste gas, and the actual heat input (HHV) using equation C-8 from 40 CFR Part 98 Subpart C.

To calculate the CO_2e emissions, the 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

XI. Boilers (EPNs: RUPK31 and RUPK32) BACT Analysis

The proposed boilers will only burn pipeline quality sweet natural gas. CO_2 will be emitted from the boilers since it is a combustion product of any carbon containing fuel. CH_4 will be emitted from the boilers as a result of any incomplete combustion. N_2O will be emitted from the boiler in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process.

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 site's affected combustion units.
- *Low Carbon Fuels* – The boilers will fire pipeline quality natural gas.
- *Good Combustion Practices and Maintenance* - 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.
- *Energy Efficient Design* – The boilers will produce steam for use throughout the plant. In addition to the inherent efficiency of the boilers themselves, heat exchangers/economizers

will be used to preheat feed water prior to entering the steam drum and to extract as much heat as practical from the boiler flue gas.

Carbon Capture and Storage

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

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible. CCS will not be considered further based on the evaluation in section IX above.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Energy efficient design, use of low-carbon fuel, and good combustion practices are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, ranking is not necessary.

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 not only of GHGs, but of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

Good Combustion Practices

Good combustion practices effectively support the energy efficient design. Thus, the economic and environmental practicability related to energy efficient design also applies to the use of good combustion practices.

Energy Efficient Design

The boilers will incorporate the following technologies; feedwater preheat, such as an economizer. 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 both GHGs and other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing further environmental benefits.

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	BACT Control(s)	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 steam package boilers - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-903-GHG
Chevron Phillips Chemical Company, Cedar Bayou Plant Baytown, TX	Ethylene Production	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT for the VHP boiler - monitor and maintain a thermal efficiency of 77% 12-month rolling average basis	2012	PSD-TX-748-GHG

ExxonMobil's boilers will each meet a thermal efficiency of 77% on a 12-month rolling average basis. This value is the same as that established for BASF and Chevron Phillips in the table above. EPA believes that this is a reasonable measure of efficient operation based on our evaluation.

The following specific BACT practices are proposed for the boilers:

- *Low Carbon Fuels* – The boilers will fire pipeline quality natural gas.
- *Good Combustion Practices and Maintenance* – The use of good combustion practices includes periodic 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. These practices will include:
    - Boiler inspection to occur, at a minimum, of every 5 years. Inspection will include:
        - Checking the integrity of burner components (tips, tiles, surrounds);
        - Inspecting burner spuds for potential fouling;
        - Inspecting burner air doors and lubrication;
        - Inspecting all burners before closing main door to check for potential debris;
        - Inspecting combustion air ducting and dampers; and
        - Checking burner spud/orifice sizes.

- Records will be maintained for any maintenance activity completed on the burners. The burners are to be inspected during routine scheduled maintenance periods.

- *Energy Efficient Operation* – The boiler will produce steam for use throughout the plant. Specific technologies utilized will include the following:
  - *FeedwaterPreheat* - Use of heat exchangers/economizers to preheat incoming feedwater to minimize fuel usage in the firebox.
  - *Flue Gas Heat Recovery* - Use of heat exchangers/economizers to use heat in the combustion gases in the boiler flue gas.

BACT for the boilers will be to maintain no less than a 77% thermal efficiency (HHV basis) on a 12-month rolling average for each boiler. ExxonMobil elects to demonstrate compliance with a 77% thermal efficiency on the boilers using the following equation:

$$Boiler\ Efficiency\ (HHV\ basis) = \frac{(steam\ flow\ rate\ x\ steam\ enthalpy) - (feedwater\ flowrate\ x\ feedwater\ enthalpy)}{Fuel\ firing\ rate\ x\ GCV} * 100$$

ExxonMobil will demonstrate compliance with the CO_2 emission limit for the boiler using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1. Equation C-5 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 Continuous Emission Monitoring System

(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, Table C-2, site specific analysis of process fuel gas, and the actual heat input (HHV). 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 (74 FR 56374 October 30, 2009). Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 12-month average, rolling monthly.

An initial stack test demonstration will be required for CO_2 emissions from the emission unit. 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 boilers and are considered a *de minimis* level in comparison to the CO_2 emissions.

XII. Analyzer Catalytic Oxidizers (EPN: PEXANALZ) BACT Analysis

For purposes of VOC control, ExxonMobil plans to install up to 35 analyzers containing TRACErase™ or equivalent catalytic oxidation technology distributed throughout the process equipment. The only practical option for control of VOC emissions from some of the analyzers is the proposed technology of catalytic oxidation powered by electricity. Due to the presence of oxygen in some of the analyzer vent streams, these vent streams cannot be recovered to the process or controlled in the Vent Collection System. Thermal oxidation was evaluated as an alternative method of control of hydrocarbons in some of the analyzer vent streams; however, this option was eliminated because of the greater increase in GHG emissions which would result from the use of natural gas fueled burners to supply sufficient oxidization temperature in the reaction zone. If thermal oxidizers were utilized the GHG emissions from natural gas combustion alone would be approximately 150 tpy of CO_2e. This would be a 400% increase in the GHG emissions from the thermal oxidizers. The TRACErase™ Hydrocarbon Emission Eliminator utilizes a constant heat source (catalytic converter) to allow effective oxidation of intermittent fugitive hydrocarbon emission streams as well as continuous hydrocarbon source streams from some of the analyzers. The units are designed to maintain temperatures in excess of 100 ^{o}F to ensure functioning of the cartridge heater and in excess of 185 ^{o}F ensure functioning of the catalyst cartridge. Annual preventative maintenance to replace the catalytic cartridge shall be performed.

Using the operating practices above will result in an emission limit for the analyzer catalytic oxidizers of 28 tpy CO_2e. ExxonMobil will demonstrate compliance with the CO_2 emission limit using the estimated gas flow through each analyzer, vapor density, vapor speciation, and a 98% destruction efficiency. The equation for estimating CO_2 emissions is as follows:

$$CO_2 = \frac{QV}{MV} * DRE * 2 * MW_{CO2} * 1/2000$$

Where:

CO_2 = Annual CO_2 mass emissions from analyzer catalytic oxidizers (short tons)
QV = Total Analyzer gas volume flow (lb/hr).
MV = Molecular weight of gas (lb/lb mole).
DRE = Destruction efficiency of analyzer catalytic oxidizers (%).
MW_{CO2} = Molecular weight of CO_2 (lb/lb mole).
1/2,000 = Conversion from pounds to short tons.
2 = Mole conversion from ethylene to carbon dioxide.

XIII. Equipment Component Fugitives (EPN: PEXFUGEM) BACT Analysis

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 lines containing natural gas and lines not in VOC service, but containing methane 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. Natural gas is 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.[6] 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 and/or components can hiss when leaking, as-observed olfactory observation is a very effective method for identifying fugitive 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 MBPP 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 natural gas and fugitive emission of methane from process lines not in VOC service, but containing methane 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 components in the service of natural gas and components not in VOC service, but containing

[6] 73 FR 78199-78219, December 22, 2008.

methane, EPA is proposing that ExxonMobil incorporate as-observed AVO as BACT for the piping components associated with this project in natural gas and fugitive emission of methane from process lines not in VOC service, but containing methane. 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) and a quarterly connector monitoring program (equivalent to the TCEQ 28LAER) for fugitive emissions control in the New Source Review (NSR) permit No. 103048 to be issued by TCEQ. EPA concurs with ExxonMobil's assessment that using the TCEQ 28VHP[7] 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 fugitive sources, and although the existing LDAR program is being imposed in this instance, it is imposed as a work practice. See 40 CFR § 51.166(b)(12) (technological and economic limitations make measurement methodology infeasible under the circumstances here).

XIV. Endangered Species Act (ESA)

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 eleven (11) species listed as federally endangered or threatened in Chambers and Liberty Counties, Texas:

[7] The boilerplate special conditions for the TCEQ 28VHP 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.

Federally Listed Species for Chambers and Liberty Counties by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS), and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Red-cockaded Woodpecker	*Picoides borealis*
Piping Plover	*Charadrius melodus*
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 eleven 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.

XV. 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 June 6, 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 an approximately 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, several historic structures including several historic-age canals, ditches, and other irrigation-related resources and a historic-age railroad grade were identified. Though irrigation and the railroad system were significant factors in the historic development of the area, none of the structures had the integrity or significance to meet the criteria for NRHP listing; therefore, none of these structures were recommended to be eligible for listing on the National Register. One historic site was identified to be potentially eligible for listing on the National Register, but it is outside the APE (greater than 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 June 10, 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.

XVI. 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.

XVII. 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]		
3UF61A 3UF61B 3UF61C	3UF61A 3UF61B 3UF61C	Flameless Thermal Oxidizers	CO_2	91,660[3]	104,413[4]	Good combustion and maintenance practices. See permit condition III.A.3.
			CH_4	5[3]		
			N_2O	1[3]		
3UFLARE62	3UFLARE62	Assisted Elevated Flare	CO_2	6,304		Good combustion and maintenance practices. See permit conditions III.A.4.
			CH_4	3		
			N_2O	2		
3UFLARE63	3UFLARE63	Multi-point Ground Flare	CO_2	7,735		Good combustion and maintenance practices. See permit condition III.A.2.
			CH_4	4		
			N_2O	2		
RUPK71	RUPK71	Regenerative Thermal Oxidizer	CO_2	2,221	2,552	Maintain a minimum combustion temperature as determined by initial compliance testing. See permit condition III.B.8
			CH_4	1		
			N_2O	1		
RUPK31 RUPK32	RUPK31 RUPK32	Boilers	CO_2	30,512	30,864	Maintain a minimum thermal efficiency of 77%. See permit condition III.C.5.
			CH_4	2		
			N_2O	1		
PEXANALZ	PEXANALZ	Analyzer Catalytic Oxidizers	CO_2	28	28	Use of Good Combustion Practices. See permit condition III.D.
PEXFUGEM	PEXFUGEM	Fugitive Emissions	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	Implementation of LDAR/AVO program. See permit condition III.E.
			CH_4	No Numerical Limit Established[5]		
Totals[6]			**CO_2**	**138,462**	**CO_2e 138,216**	
			CH_4	**32**		
			N_2O	**7**		

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 for the flameless thermal oxidizers (FTOs) applies to all three units combined in a vent recovery system.
4. The CO_2e TPY limit for the flameless thermal oxidizers (FTOs), Elevated Flare, and Multipoint Ground Flare applies to all units combined in the vent recovery system.
5. Fugitive process emissions from EPN PEXFUGEM are estimated to be 2 TPY CO_2, 17 TPY of CH_4, and 359 TPY CO_2e. In lieu of a numerical emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
6. Total emissions include the PTE for fugitive emissions. Totals are given for informational purposes only and do not constitute emission limits.

Magee, Melanie

From:	Hurst, Benjamin M <benjamin.m.hurst@exxonmobil.com>
Sent:	Thursday, February 11, 2016 7:45 AM
To:	Magee, Melanie
Cc:	Mak, Christy
Subject:	RE: Additional Information Request for Review of Rescission Requests for: PSD-TX-102982-GHG and PSD-TX-103048-GHG
Attachments:	MBPP PE Expansion Table 1F.pdf

Melanie,

Attached please find the Table 1F for MBPP PE Expansion Project provided to the TCEQ in December 2012. Even though the attached Table 1F was marked "CONFIDENTIAL", we no longer consider information provided on this table confidential.

Table 1F was not necessary for the BOP Ethylene Expansion Project as no increases to any of the established PAL limits were requested.

If you have any additional questions or I can be of further assistance, please do not hesitate to contact me.

Thank you,

Benjamin M. Hurst
Ph: (281) 834-7728
Email: benjamin.m.hurst@exxonmobil.com

From: Magee, Melanie [mailto:Magee.Melanie@epa.gov]
Sent: Thursday, February 04, 2016 6:27 AM
To: Hurst, Benjamin M
Cc: Mak, Christy
Subject: RE: Additional Information Request for Review of Rescission Requests for: PSD-TX-102982-GHG and PSD-TX-103048-GHG

Thank you so much.

From: Hurst, Benjamin M [mailto:benjamin.m.hurst@exxonmobil.com]
Sent: Wednesday, February 03, 2016 4:31 PM
To: Magee, Melanie <Magee.Melanie@epa.gov>
Cc: Mak, Christy <christy.mak@exxonmobil.com>
Subject: RE: Additional Information Request for Review of Rescission Requests for: PSD-TX-102982-GHG and PSD-TX-103048-GHG

Ms. Magee,

I wanted to let you know that I received your e-mail. We will work on your request and will respond, as soon as possible, but no later than next week. If you have any questions or concerns about the timing, please feel free to contact me.

Thank you,

Benjamin M. Hurst
Ph: (281) 834-7728
Email: benjamin.m.hurst@exxonmobil.com

TABLE 1F
AIR QUALITY APPLICATION SUPLEMENT
Revised December 2012

Permit No.: **103048**	Application Submittal Date: **May 2012**
Company: **ExxonMobil Chemical Company**	
RN: **102501020**	Facility Location: **Mont Belvieu**
City: **Mont Belvieu**	County: **Chambers**
Permit Unit I.D.: **PE**	Permit Name: **TBD**
Permit Activity: **X** New Source Modification	
Project or Process Description: **The proposed permit is to authorize construction of a new polyethylene production unit at an existing plastics plant**.	

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS						
	Ozone		**CO**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**Other** [1]
	VOC	**NO_X**					
Nonattainment? (yes or no)	YES	YES	NO	NO	NO	NO	NO
Existing site PTE (tpy)?	>25	> 25	> 100	-	-	-	-
Proposed project emission increases (tpy from 2F)[3]	70.73	22.66	54.27	8.33	4.12	4.25	23.79
Is the existing site a major source? [2] If not, is the project a major source by itself? (yes or no)	YES	YES	YES	YES	YES	YES	YES
If site is major, is project increase significant?	YES	YES	NO	NO	NO	NO	NO
If netting required, estimated start of construction?	3/1/2013	3/1/2013	-	-	3/1/2013	-	-
Five years prior to start of construction contemporaneous	3/1/2008	3/1/2008	-	-	3/1/2008	-	-
Estimated start of operation period	2Q2016	2Q2016	-	-	2Q2016	-	-
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	20.71	17.36					
FNSR APPLICABLE? (yes or no)	NO	NO	NO	NO	NO	NO	NO

[1] Other PSD pollutants: PM

[2] Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

[3] Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

	Plant Manager	
Signature	Title	Date

~~CONFIDENTIAL~~