Statement of Basis

Greenhouse Gas Prevention of Significant Deterioration Preconstruction Draft Permit for ONEOK Hydrocarbon, L.P., Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant

Permit Number: PSD-TX-1396-GHG

May 2014

This document serves as the Statement of Basis (SOB) 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 January 23, 2014, ONEOK Hydrocarbon, L.P. (ONEOK) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification at ONEOK's Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant. At EPA's request, ONEOK submitted additional information on February 24, 2014. In connection with this same proposed modification, ONEOK submitted an application for a minor source amendment to their existing NSR permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 18, 2014. The proposed project would expand operations at ONEOK's existing Mont Belvieu NGL Fractionation Plant by adding two (2) additional 75,000 (nominal) barrel per day (bbl/day) fractionation plants (Frac-3 and Frac-4) to process demethanized natural gas mixture (Y-grade) into ethane, propane, isobutane, normal butane, and natural gasoline purity products. After reviewing the application, EPA has prepared the following SOB and draft PSD permit that, when finalized, will authorize the construction of air emission sources at the ONEOK Hydrocarbon Mont Belvieu NGL Fractionation Plant.

This SOB provides the information and analysis used to support EPA's decisions in drafting the PSD permit. It includes a description of the facility and proposed modification, the PSD permit requirements based on BACT analyses conducted on the proposed new units, and the compliance terms of the permit.

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

Applicant

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II. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan (FIP) that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. See 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

III. Facility Location

The ONEOK Mont Belvieu NGL Fractionation Plant is located in Chambers County, TX. This area is currently designated as “nonattainment” for ozone. The nearest Class I area is the Caney Creek Wilderness area in Arkansas, which is located over 400 kilometers from the site. The geographic coordinates for the facility are as follows:

Latitude: 29° 51’ 30” North
Longitude: -94° 53’ 25” West

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

Figure 1: ONEOK NGL Fractionation Plant

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

EPA concludes that ONEOK's application is subject to PSD review for GHGs because the project would result in an emissions increase of 75,000 tpy CO_2e or more as described at 40 CFR § 52.21(b)(49)(v)*(b)* and an emissions increase greater than zero tpy on a mass basis as described at 40 CFR § 52.21(b)(23)(ii) (ONEOK calculates an increase of 466,049 tpy CO_2e). 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.

As noted above in Section III, EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR section 52.21 (except paragraph (a)(1)). *See,* 40 CFR § 52.2305. EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with 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 proposed project.

V. Project Description

The proposed GHG PSD permit, if finalized, will allow ONEOK to construct two (2) new 75,000 (nominal) barrel per day (bbl/day) fractionation units (Frac-3 and Frac-4) at the Mont Belvieu facility. EPA Region 6 issued a GHG PSD Permit for the construction of a 75,000 (nominal) barrel per day (bbl/day) fractionation unit (Frac-2) at the Mont Belvieu facility on July 23, 2013. The new Frac-3 and Frac-4 units will fractionate Y-grade NGL into the constituent products, including ethane, propane, isobutane, normal butane, and natural gasoline for sale to customers. The proposed process trains each include: an amine contactor/amine regenerator for inlet gas treatment, a deethanizer, a depropanizer, a debutanizer, natural gasoline treatment, a deisobutanizer, post fractionation butane sulfur removal, and a number of process related utilities and ancillary operations. Each step in the fractionation process is described in detail below:

<u>Inlet Gas Treatment</u>

The Y-grade feedstock will be received by process piping, water washed and then piped to an amine contactor where CO_2 and H_2S will be removed, per customer specifications. The treated feed will then be sent to the deethanizer. The rich amine solution will be directed to the amine regeneration unit where the CO_2 and H_2S will be stripped out in the amine regenerator and the lean amine recycled back to the contactor. The vent stream from the amine regenerator, which is primarily composed of CO_2 and H_2S, will be piped directly to the plant's heaters and combusted. Flash gas from the amine regeneration unit will be piped to the flare gas recovery unit (FGRU) where heavier components will be recovered before the light ends are piped to the facility's heaters and combusted.

Deethanizer

After pre-treatment, the feed stream will be directed to the deethanizer. Ethane will be separated and removed as a product. Deethanizer bottoms will be directed to the depropanizer for additional fractionation.

Depropanizer

Bottoms from the deethanizer will be piped to the depropanizer. Propane will be separated and removed as a product. Depropanizer bottoms will be directed to the debutanizer for additional fractionation.

Debutanizer

Bottoms from the depropanizer will be piped to the debutanizer. The debutanizer will separate the feedstock into two fractions: mixed butanes (isobutane and n-butane), and natural gasoline. The mixed butanes will be piped to the deisobutanizer for additional fractionation. The natural gasoline will be directed to an additional treatment unit.

Natural Gasoline Treatment

The natural gasoline stream must undergo additional treatment to remove naturally occurring sulfur compounds in order to prevent corrosion of downstream equipment and to meet customer specifications. The sulfur compounds (mercaptans) will be catalytically converted to disulfide oil through an oxidation process over a catalyst bed. Vent streams from the treatment unit will be directed to the facility's heaters and combusted. The treated natural gasoline will be removed as a product.

Deisobutanizer

The mixed butanes from the debutanizer will be piped to the deisobutanizer, for fractionation into n-butane, and isobutane. Both isomers will then undergo additional treatment.

Butanes Treatment

Both the n-butane and isobutane can contain naturally occurring sulfur compounds (including mercaptan) that must be removed. Each isomer will be treated independently after fractionation in a caustic contactor which will strip out the sulfur compounds. Off gases from the treatment unit will be piped to the facility's heaters and combusted. The treated n-butane and isobutane will be removed as products.

Heaters/Hot Oil System

The heat required for all of the process units will be supplied by a hot oil system. ONEOK has proposed construction of six, 154 MMBtu/hr oil heaters (maximum short-term firing rate, HHV basis) as part of the facility expansion. These will be fired with a combination of natural gas and recovered gas from the flare gas recovery unit (FGRU) and vent streams from process equipment. Flue gas from the heaters will be treated with selective catalytic reduction (SCR) prior to release into the atmosphere.

Flare/FGRU

Process vent gases will be collected throughout the plant and routed to the flare header. The project proposes to add one (1) new flare. The flare header is a closed-vent system. The flare header will collect vapors from process vent streams and relief valves. The flare header may also process emergency upsets and startup, shutdown, or maintenance activities. Rather than sending all waste gases to the flare for combustion, some of the vapors will be routed to a FGRU to be recovered as feedstock or routed to the hot oil heaters as fuel.

The FGRU will be composed of electric driven compressors which will recover the vapors via condensing and pump them to the deethanizer feed or to storage. Any uncondensed vapors will be routed to the heaters for use as fuel. The proposed FGRU is designed to recover all of the vent gas from normal operations. The flare will normally combust pilot and sweep gas during routine operations. During upset conditions and/or other startup and shutdown or maintenance activities (at which time the FGRU is unavailable) most vapors will be combusted in the flare.

Cooling Tower

Various processes within the Frac-3 and Frac-4 units will require non-contact cooling water. Two (2) new cooling towers are proposed for cooling and re-circulation of the necessary cooling water. Recirculated cooling water will be cooled by ambient air via evaporation, and pumped to the various units as needed. Although the cooling water system will be closed loop and non-contact, the potential exists for leaks in the various process units to cause VOCs to be entrained in the cooling water and released during evaporation. Particulate matter is also typically entrained in drift loss from a cooling tower.

Tanks

The proposed Frac-3 and Frac-4 units will include tanks for the storage of spent materials, amine, cold oil, lube oil, water treatment chemicals, and wastewater. The tanks are not a source of GHG emissions.

Loading Activities

Finished products will be transported offsite via process piping. No fugitive emissions from product loading are expected.

Waste materials will be transported offsite via truck. Fugitive emissions from these activities have been included in the emission calculations for the proposed project.

Pressurized loading and unloading of propane refrigerant and ammonia will also occur onsite.

Emergency Engines

Diesel engines will power an emergency air compressor and firewater pump. A natural gas-fired engine will power an emergency generator. Given that the actual configuration and sizing of this equipment may vary, the represented emissions cases include conservative emission estimates by accounting for the maximum expected horsepower of the engines.

Maintenance, Startup, and Shutdown (MSS)

Emissions can occur when lines or equipment are de-pressured and purged to the flare and when they are opened to the atmosphere. MSS emissions include all operations that open lines and equipment to the atmosphere, such as for equipment commissioning/startup, unit shutdown, vessel inspection, valve maintenance, rupture disk replacement, pump maintenance, gasket/bolt replacement, and instrumentation maintenance.

VI. General Format of the BACT Analysis

The BACT analyses for this draft permit were conducted by following the "top-down" BACT approach outlined in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011). The five steps in the "top-down" BACT process 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.

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

VII. Applicable Emission Units

The majority of the GHG emissions associated with the proposed Frac-3 and Frac-4 units will be generated by combustion sources. Stationary combustion sources primarily emit CO_2, but also emit relatively small amounts of N_2O and CH_4. Emissions from the following units or processes are within the scope of the BACT analysis submitted by ONEOK in their application:

- Hot Oil Heaters (EPNs: H-07, H-08, H-09, H-10, H-11 and H-12)
- Process Vents (FIN: VENTS; EPNs: H-07, H-08, H-09, H-10, H-11 and H-12)
- Equipment Leak Fugitives (EPN: FUG-04 and FUG-05)
- Cooling Towers (EPN: CT-05 and CT-06)
- Emergency Engines (EPNs: ENG-07, ENG-08, and ENG-09)
- Flare (EPN: FL-02)
- Maintenance, Start-up, and Shut-down (EPN: MSS-FUG-3)

VIII. Hot Oil Heaters (EPNs: H-07, H-08, H-09, H-10, H-11, and H-12) BACT Analysis

GHG emissions, primarily CO_2, are generated from the combustion of natural gas enriched with recovered gas from the flare gas recovery unit (FGRU) in the proposed heaters. The new fractionation units (Frac-3 and Frac-4) will utilize six hot oil heaters each with a maximum firing rate of 154 MMBtu/hr (higher heating value - HHV). However, the anticipated sustainable design firing rate of the heater burners is equivalent to 127 MMBtu/hr (lower heating value - LHV) or 140 MMBtu/hr (HHV). EPA took the range of firing rates that are possible for the heaters at this project to utilize into account when assessing its GHG emissions: 154 MMBtu/hr is used for hourly emission calculations used to calculate allowable emission rates, since any operation at this level is likely to be on a short-term basis; 127 MMBtu/hr (LHV basis) is used for the output-based CO_2 limit calculated on a long-term, 365-day rolling average basis, since operation at such a low level will occur at unpredictable intervals; and 140 MMBtu/hr is used in the annual CO_2e emission calculations since this is the most likely firing rate that will be utilized.

The hot oil heaters will serve as a control device for the amine regeneration vent streams and for the natural gasoline and butane sulfur treating processes. The hot oil heaters will supply heat to the amine regeneration unit, the deethanizer, depropanizer, debutanizer, deisobutanizer, and other miscellaneous users. Flue gas from the hot oil heaters is treated with selective catalytic reduction (SCR) prior to being released to the atmosphere.

Step 1 – Identification of Potential Control Technologies for GHGs

- Energy Efficient Design
  - Installation of energy efficient burners
  - Draft/Trim instrumentation to control the amount of combustion air available in the heaters
  - Waste heat recovery (economizer/air pre-heater)
  - Insulation
  - Reduction of air leakage
  - Reduction of slagging and fouling of heat transfer surfaces
- Energy Efficient Operating Procedures
  - Initial heater tuning and testing
  - Annual heater tune-up
  - Optimization
- Carbon Capture and Storage (CCS)
  - Requires Capture of CO_2 , Transportation of captured CO_2 to a suitable storage location, and Permanent storage of CO_2
- Use of Low-Carbon Fuels
  - Switching to lower carbon fuels to minimize CO_2 emissions

Step 2 – Elimination of Technically Infeasible Alternatives

EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is available and applicable to the source type under review. *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), pg. 33. CO_2 capture technologies, including post-combustion capture, have not been demonstrated in practice on hot oil heaters. Moreover, while CO_2 capture technologies may be commercially available generally, we believe that there is insufficient information at this time to conclude that CO_2 capture is applicable to the proposed hot oil heaters at ONEOK, due to the low volume and low concentration of CO_2 streams.[1] As a result, EPA

[1] ONEOK provided information on the CO_2 concentration of the hot oil heater exhaust gas. In this email ONEOK states "The hot oil heaters for this project are predicted to have a CO_2 exhaust gas concentration of only 8.4 mole percent (wet basis)". http://www.epa.gov/region6/6pd/air/pd-r/ghg/oneok-frac3frac4-response030314.pdf

believes that CCS is technically infeasible for the hot oil heaters and can be eliminated as BACT.[2]

In regards to the remaining control options, EPA finds that all are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Energy efficient design and operational measures (ONEOK estimates that this will achieve as much as a 10-15% reduction in GHG emissions from a baseline of no energy efficient measures)
- Use of low carbon fuel (Zero - natural gas was the intended fuel for the project so no additional reductions were identified for the use of lower-carbon fuel.)

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

[NOTE: As explained above in the Step 2 analysis, EPA has determined that CCS is technically infeasible for the hot oil heaters at this project and can be eliminated as BACT. However, even if CCS were not eliminated at Step 2, ONEOK has provided analysis with its permit application demonstrating that CCS can also be eliminated as BACT for this project in Step 4, based on the excessive costs associated with use of CCS, as well as negative environmental and energy impacts.]

<u>Energy Efficient Design, Energy Efficient Operating Practices, and Use of a Low Carbon Fuel</u>

EPA anticipates no adverse energy, environmental, or economic impacts as a result of employing these measures.

[2] Since CCS is eliminated in Step 2 of the BACT analysis, EPA does not need to consider CCS in the later BACT analysis, including cost analysis in Step 4 of the BACT analysis. ONEOK did, however, submit a cost analysis for CCS as part of the application, and that analysis is included in the administrative record.

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
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Trim Heaters (17.4 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/each) 4 Regenerator Heaters (3 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters per plant (one of each heater per plant) of 1,102.5 lbs CO_2/MMSCF 365-day average, rolling daily for each plant	2012	PSD-TX-1264-GHG
Enterprise Products Operating LLC, Eagleford Fractionation Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regenerant Heaters (28.5 MMBtu/hr each	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis. Regenerant heaters with good combustion practices.	2012	PSD-TX-154-GHG
Energy Transfer Partners, LP, Lone Star NGL Mont Belvieu, TX	2 Hot Oil Heaters (270 MMBtu/hr each) 2 Regenerant Heaters (46 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters - 7.6 lb CO_2/bbl of NGL processed per heater. Regenerator Heaters - 1.3 lbs CO_2/bbl of NGL processed per heater. 365-day average, rolling daily	2012	PSD-TX-93813-GHG
Copano Processing L.P., Houston Central Gas Plant Sheridan, TX	2 Supplemental Heaters (25 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices, and Limited Operation	Each heater will be limited to 600 hours of operation on a 12-month rolling basis.	2013	PSD-TX-104949-GHG

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
KM Liquids Terminals LLC, Galena Park Terminal Galena Park, TX	2 Hot Oil Heaters (247 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis.	2013	PSD-TX-101199-GHG
Targa Gas Processing LLC, Longhorn Gas Plant Decatur, TX	Glycol Reboiler (2 MMBtu/hr) Mol Sieve Heater (12 MMBtu/hr) Hot Oil Heater (98 MMBtu/hr)	Energy Efficiency/ Good Design & Combustion Practices	1,783.23 lb CO_2/ MMSCF for three heaters combined 365-day rolling average	2013	PSD-TX-106793-GHG
ONEOK Hydrocarbon, Mont Belvieu Fractionation Plant (Frac-2)	3 Hot Oil Heaters (154 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices; Use of Low Carbon fuel	14.25 lbs CO_2/bbl y-grade feed for all heaters combined (365-day rolling average). Maintain an exhaust temperature of 385 °F or less for each heater (365-day rolling average).	2013	PSD-TX-106921-GHG
Lone Star Fractionation Plant (Frac III Plant)	1 Hot Oil Heater (215 MMBtu/hr) 1 Regeneration Heater (59 MMBtu/hr)	Energy Efficiency/ Good Design & Combustion Practices; Use of Low Carbon fuel	Hot Oil Heaters - 7.12 lb CO_2/bbl of NGL processed per heater. Regenerator Heaters - 1.95 lbs CO_2/bbl of NGL processed per heater.	2014	PSD-TX-110274-GHG

The Enterprise Eagleford Fractionation and Energy Transfer Partners Lone Star NGL BACT determinations are both applied to natural gas liquids (NGL) fractionation facilities. The Lone Star NGL facility produces a higher grade of propane for export purposes that requires a higher heat duty than the Enterprise facility. ONEOK has proposed an output-based BACT limit of 14.25 lb CO_2/bbl of Y-grade feed processed for all six of the hot oil heaters combined, which is the same as the BACT limit for the three hot oil heaters installed in the Frac-2 project at this facility. The Lone Star NGL facility has an output-based BACT limit of 7.6 lb CO_2/bbl of NGL processed per heater. The two hot oil heaters at the Lone Star NGL facility have a heat input rate of 270 MMBtu/hr each. The three hot oil heaters installed by ONEOK in Frac-2 have a heat input rate of 154 MMBtu/hr each, combined they have a heat input rate of 462 MMBtu/hr. The six hot oil heaters proposed by ONEOK in Frac-3 and Frac-4 have a heat input rate of 154

MMBtu/hr each, combined they have a heat input rate of 924 MMBtu/hr. The Lone Star NGL heaters are approximately 54% larger than those proposed by ONEOK on an individual basis, but the ONEOK heaters combined have a heat input rate 3.5 times greater than each of Lone Star's hot oil heaters. The BACT limit proposed by ONEOK for all six hot oil heaters combined is higher than the BACT limit for the Lone Star NGL hot oil heater by 46%. This increase is mainly attributed to the greater overall heat input of the ONEOK hot oil heaters. Also, the Lone Star facility design includes two separate regeneration heaters for their process where EPA established a separate BACT limit for those heaters in that permit, but in ONEOK's design, the heat for the regeneration process is provided by the hot oil system with no separate regeneration heaters. The higher BACT emission limit proposed for this permit is also based on the feed composition and processing rate that is expected at the ONEOK facility. This BACT limit only applies to the firing of natural gas and recovered flare gas in the hot oil heater burners. It does not include the emissions attributed to the control of the process vent gases from the amine regeneration vent and other process vents. As shown above, EPA Region 6 analyzed the proposed BACT and has determined it is consistent with other BACT determinations for similar units.

The following specific BACT practices are proposed by ONEOK for the hot oil heaters:

- *Energy Efficient Heater Design*
    - Use of high efficiency burners to allow complete combustion and low excess air;
    - Draft/trim instrumentation and controls to optimize excess O_2;
    - Firebox and stack O_2 instrumentation to identify and control O_2 leaks;
    - Economizer/air preheater for waste heat recovery and reduction of flue gas temperature;
    - Installation of proper refractory and insulation materials to reduce heat loss; and
    - Combustion of natural gas and recovered flare gas to reduce fouling of heat transfer surfaces.
- *Energy Efficient Operating Practices*
    - Combustion tuning and optimization to maximize efficiency, both at start-up and as part of an annual efficiency audit;
    - Preventive maintenance program and regular visual inspections of heaters;
    - Annual tune-up to include burner inspection and cleaning, flame inspection and optimization, air-to-fuel ratio, and CO optimization; and
    - Monitoring the flue gas temperature.
- *Use of Low-Carbon Fuels* - ONEOK will combust natural gas, recovered flare gas, and process vent gases in the heaters.

BACT Limits and Compliance

Each hot oil heater will have an annual GHG limit of 71,775 tons CO_2e/year, based on a 365-day rolling total. Additionally, the six heaters shall have a combined, output based limit of 14.25 lb CO_2/barrel (bbl) of y-grade feed. This BACT limit, and the annual limit of 71,775 TPY of CO_2e, only applies to the firing of natural gas and recovered flare gas in the hot oil heater burners. Additionally, ONEOK shall maintain a maximum flue gas exit temperature of 385°F on a 365-day rolling average basis (except during periods of start-up and shut-down). Flow and fuel usage shall be monitored in accordance with 40 CFR Part 98. Additionally, the flue gas temperature must be continually monitored on each hot oil heater while it is operating.

Compliance with the CO_2 limit shall be determined using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at §98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the greatest (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. 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. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily.

An initial stack test demonstration will be required for CO_2 emissions from each emissions unit. An initial stack test demonstration for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emissions are less than 0.10 % of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions.

IX. Process Vents (EPNs: H-07, H-08, H-09, H-10, H-11, and H-12) BACT Analysis

CO_2 from the amine regenerator vent represents the bulk of the GHG emissions from process vents. Some additional GHG emissions are also generated from CH_4 entrained in process vents and from CO_2 emissions generated through the combustion of process gases in the hot oil heaters. These streams are part of the Flare Gas Recovery system and ONEOK requested to monitor these streams separately.

Step 1 – Identification of Potential Control Technologies for GHGs

- Combustion of residual hydrocarbons as fuel in the hot oil heaters
- Destruction (combustion) of residual hydrocarbons in a control device
- Carbon Capture and Storage (CCS)

Step 2 – Elimination of Technically Infeasible Alternatives

As explained in the Step 2 analysis for the hot oil heaters provided above, CO_2 capture technologies, including post-combustion capture, have not been demonstrated in practice on process vent streams such as these, nor are they believed to be available and applicable for this proposed project. Accordingly, CCS is considered technically infeasible for this project will not be considered further in this BACT analysis for process vents. (In addition, as noted in the Step 4 analysis for the hot oil heaters, CCS can also be eliminated as BACT for the project given the costs of a CCS system and the potential negative environmental and energy impacts.)
Both remaining technologies were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Combustion in a control device would require supplementary fuel and would generate additional GHG emissions. Therefore, the remaining technologies were ranked as follows:

- Use of the residual gases as fuel in the process heaters
- Combustion of the residual gases in a control device, such as a flare or thermal oxidizer

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

ONEOK's proposed design incorporates the top control option. ONEOK is proposing to burn residual hydrocarbons as fuel in hot oil heaters. No adverse collateral impacts were identified.

Step 5 – Selection of BACT

ONEOK proposes to burn the residual gas as fuel in the hot oil heaters.

BACT Limits and Compliance

GHG emissions from residual gases routed to and combusted in the hot oil heaters will be limited to 30,003 tons CO_2e/yr based on a 365-day rolling total. The draft permit shall require quarterly sampling of the process vent gas, as well as measurement of the vent gas flow to the process heaters.

ONEOK will demonstrate compliance with the CO_2 emission limit for the process vent emissions using the site specific analysis for process vent gas. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

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

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to § 98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for HHV at § 98.33(a)(2)(ii).
MW = Annual average molecular weight of the gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at § 98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in § 98.6.
44/12 = Ratio of molecular weights, CO_2 to carbon.
0.001 = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

The proposed permit also includes an alternative compliance demonstration method in which ONEOK may install, calibrate, and operate a CO_2 Continuous Emissions 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). Comparatively, the emissions from CO_2 contribute the greatest (greater than 99%) to the overall emissions from the heaters. 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. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily.

X. Equipment Leak Fugitives (FUG-04 and FUG-05) BACT Analysis

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 25 TPY CO_2e. Fugitive emissions of methane account for less than 0.005 % of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

- Leak Detection and Repair (LDAR) – Method 21 monitoring of valves, pumps, flanges/connections, etc., for leak detection and subsequent repair.
- Enhanced LDAR – Enhancements to LDAR program, including lower threshold for a determination that a piece of equipment is leaking and requires repair, increased. monitoring frequency, use of "leakless" or "low-leak" equipment where appropriate
- Optical Gas Imaging LDAR – Use of IR camera to identify leaks.

Step 2 – Elimination of Technically Infeasible Alternatives

All three control technologies were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

ONEOK ranked the technically feasible options in order of control effectiveness

- Enhanced LDAR – includes leak detection limit of 500 ppmv for most equipment types, including flanges.
- LDAR – includes leak detection limit of 500-10,000 ppmv. No instrument monitoring of connections.

- Optical Gas Imaging LDAR – according to ONEOK's analysis, generally has a leak detection limit of greater than 10,000 ppmv.

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

Because ONEOK is proposing to implement the top control option in Step 3 – Enhanced LDAR – there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

The process lines in VOC service are proposed to incorporate the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions control in the New Source Review (NSR) permit No. 106921 to be issued by TCEQ. The TCEQ 28LAER LDAR program is an enhanced LDAR program that has a lower threshold for determining leaks, increased monitoring frequency, and use of "leakless" or "low leak" equipment where appropriate. ONEOK has proposed to implement enhanced LDAR practices as BACT for GHG fugitive emissions, and will operate according to TCEQ's 28LAER program, with quarterly flange/connector monitoring. EPA concurs with ONEOK's assessment that using the TCEQ 28LAER[3] 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 small amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XI. Cooling Towers (CT-05 and CT-06) BACT Analysis

GHG emissions from cooling towers are the result of potential leaks from heat exchangers into cooling water which would be stripped and emitted from the cooling towers associated with the proposed Project. Methane is present in variable concentrations in process streams, with highest concentrations in natural gas. Methane entrained in the cooling water could be air-stripped during the evaporative cooling of the water in the cooling towers generating GHG emissions.

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[3] 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.

Step 1 – Identification of Potential Control Technologies

ONEOK's application identified only one available technology to control GHG emission from the cooling tower: leak detection through monthly monitoring of cooling water and the subsequent repair of any heat exchangers that have been determined to be leaking.

A detailed analysis under Steps 2-4 is not necessary because the applicant has selected the only available control option.

Step 5 – Selection of BACT

ONEOK has proposed cooling tower monitoring and repair as BACT for the cooling towers. The method for monitoring leaks in a heat exchanger/cooling tower does not differentiate between VOCs, and CH_4. Therefore, a numerical BACT limit is technically infeasible. BACT for the cooling towers shall consist of a monthly monitoring program, consistent with the TCEQ Appendix P Air Stripping method[4]. This method has been approved as an acceptable method for determining in heat exchange systems that are in organic Hazardous Air Pollutant (HAP) service at petroleum refineries 40 CFR Part 63 Subpart CC (74 FR 55671)[5]. Leak thresholds and timelines for repair will be consistent with the TCEQ air permit requirements for VOC emissions.

XII. Emergency Engines (EPNs: ENG-07, ENG-08 and ENG-09) BACT Analysis

The proposed facility design includes emergency engines to power the emergency air compressor, the emergency generators and firewater pumps. GHG emissions from these engines result from the combustion of diesel fuel and natural gas and are comprised primarily of CO_2, with CH_4 and N_2O present in smaller quantities.

Step 1 – Identification of Potential Control Technologies

- Energy Efficient Design – Reduce the amount of fuel necessary by the use of Tier 3 efficient diesel engines that are compliant with the non-road, compression ignition standards at 40 CFR 89.112. Reduce the amount of fuel necessary by natural gas-fired engines that are compliant with the standards at 40 CFR Part 60, Subpart IIII and Subpart JJJJ.

[4] Appendix P "Cooling Tower Monitoring" can be found at http://www.tceq.texas.gov/assets/public/compliance/field_ops/guidance/samplingappp.pdf
[5]See http://www.epa.gov/ttn/atw/petrefine/fr28oc09.pdf

- Energy Efficient Operating Practices – Increase engine efficiency through operational practices including initial tuning/testing, annual tune-ups, limiting hours of operation for testing
- Use of lower-carbon fuels

Step 2 – Elimination of Technically Infeasible Alternatives

ONEOK's analysis determined that the design and operational parameters designed to increase the engines' efficiency are technically feasible. However, due to the fact that emergency engines are designed to operate during disruptions of availability of other fuel supplies or power sources, the use of lower-carbon fuels (such as natural gas) for all engines, which may experience fuel supply disruptions during natural disasters and emergencies, was determined to be technically infeasible and eliminated from further consideration.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining two control technologies, energy efficient design and operation, were ranked in combination as the top control option. ONEOK estimated that potential reduction in GHG emissions is in the 10-15% range with the implementation of both of these measures.

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

Because ONEOK is proposing to implement both of the remaining two options, a detailed energy, environmental and economic impact analysis is not required under Step 4.

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the emergency engines:

- Energy Efficient Design - ONEOK will install efficient Tier 3 design diesel engines for the emergency air compressor and firewater pump as found at 40 CFR § 89.112 and is in compliance with 40 CFR 60, Subpart IIII. ONEOK will install a natural gas fired emergency generator that complies with 40 CFR 60, Subpart JJJJ
- Energy Efficient Operation
  - Initial engine tuning and testing.
  - Annual tune-ups to include changing the oil and filter, inspecting hoses and belts every 500 hours of operation or annually, whichever comes first.
  - Limiting hours of operation for testing to 100 hours/year for each engine.

BACT Limits and Compliance

Using the practices identified above results in an emission limit of 15 TPY CO_2e for the emergency generator engine, 28 TPY for the emergency air compressor engine, and 29 TPY CO_2e for the firewater pump engine for non-emergency operations. Additionally, each of the emergency engines shall be limited to 100 hours/year of non-emergency operation. ONEOK shall employ good combustion practices, including annual tune-ups and manufacturer's recommended inspections and maintenance.

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. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day average, rolling daily. Additionally, ONEOK shall maintain records of fuel usage, hours of operation, and maintenance/tune-ups performed on the engines.

XIII. Flare (EPN: FL-02) BACT Analysis

GHG emissions from the flare are generated through process gases that are vented to and combusted in the flare and from the combustion of natural gas in the pilots. The flare system is equipped with a flare gas recovery unit (FGRU). The FGRU will send the recovered flare gas to the hot oil heaters to be utilized as a fuel. The process vent gases are collected throughout the plant and routed to the flare header. The flare header is a closed-vent system. The flare header collects vapors from process vent streams and relief valves from MSS activities. CO_2 comprises the bulk of the GHG emissions from the flares, with CH_4 and N_2O being present in lesser amounts.

Step 1 – Identification of Potential Control Technologies

- Good Combustion Practices – Implement good combustion practices in the flare, and operate flare in compliance with 40 CFR 60.18
- Minimize Amount of Gas Flared – Reduce amount of gas flared through good operating practices and use of a flare gas recovery unit (FGRU)

Step 2 – Elimination of Technically Infeasible Alternatives

Both options were determined to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Use of both good combustion practices and flare gas recovery were evaluated together as the top option. ONEOK estimated that GHG emissions from the flare could thereby be reduced by approximately 90%. Compliance with 40 CFR 60.18 requires a destruction efficiency of 98% for all hydrocarbons, and 99% for hydrocarbons with two carbons or less, including CH_4. Because the combination of all of the control options in Step 1 are being proposed by the applicant, a ranking of the individual control options 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

Because the combination of all of the control options in Step 1 are being proposed by the applicant, there is no need to evaluate the economic, energy and environmental impacts of the proposed project.

Step 5 – Selection of BACT

EPA has reviewed and concurs with ONEOK that the following are BACT:

- Good Combustion Practices – Implement good combustion practices in the flare, and operate flare in compliance with 40 CFR 60.18
- Minimize Amount of Gas Flared – Reduce amount of gas flared through good operating practices and use of a flare gas recovery unit (FGRU)

GHG emissions from the flare resulting from normal and MSS operations of the Frac-3 and Frac-4 process units will be limited to 5,250 tons CO_2e/year based on a 365-day rolling average. The flow will be continually monitored at the flare header and recorded electronically when emissions are directed to the flare. The composition of the process vent streams and relief valve vapors from MSS will be determined on an hourly basis by a composition analyzer or equivalent at the flare header. The composition analyzer will be calibrated and will identify at least 95% of the compounds in the waste gas. Metered supplemental fuel (natural gas) will also be continually monitored to maintain the minimum heating value necessary for flame stability. The presence of flame will be continually monitored by thermocouple or IR camera. The flow meter and analyzers used for flare compliance will be operational at least 95% of the time when the flare is operational, averaged over a calendar year. The flow meter will be calibrated or certified biannually. The composition analyzer will have a single point calibration check monthly when the flare is receiving waste gas vents. Implementing these control practices and design technologies results in an emission limit of 5,250 TPY CO_2e for EPN FL-02.

ONEOK will demonstrate compliance with the CO_2 emission limit using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-1, and the site specific composition and flow for process gas (MSS emission sources). The equation for estimating CO_2 emissions as specified in 40 CFR 98.253(b)(1)(ii)(A) is as follows:

$$CO_2 = 0.99 \times 0.001 \times \left(\sum_{p=1}^{n} \left[\frac{44}{12} \times (Flare)_p \times \frac{(MW)_p}{MVC} \times (CC)_p \right] \right) * 1.102311$$

Where:

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

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y, site specific analysis of process fuel gas, and the actual heat input (HHV).

XIV. MSS Emissions (MSS-FUG-3) BACT Analysis

GHG emissions from maintenance, start-up, and shut-down (MSS) activities occur from degassing process vessels and equipment. The GHG emissions are primarily CH_4.

Step 1 – Identification of Potential Control Technologies for GHGs

The only technology identified by ONEOK as being available is good operational practices. Degassing emissions will be minimized by pumping liquids for recovery, depressurizing and purging vessels to either the flare or the flare gas recovery unit, and venting to the atmosphere only when concentrations are below 10,000 ppmv where practical.

A detailed analysis under Steps 2-4 is not necessary because the applicant has selected the only available control option.

Step 5 – Selection of BACT

EPA concurs with ONEOK that good operational practices are proposed as BACT. A numerical BACT limit was not determined to be technically feasible for MSS emissions released to the atmosphere because work practices are difficult to numerically quantify for purposes of emission limits. ONEOK will maintain records of significant MSS activities to include the date, time, and duration. Additionally, ONEOK will monitor residual hydrocarbon concentrations in process equipment vented to the atmosphere using an LEL meter or Organic Vapor Analyzer.

X. 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, ONEOK Hydrocarbon, LP ("ONEOK"), and its consultant, Burns & McDonnell, thoroughly reviewed, and adopted by EPA.

A draft BA has identified ten (10) species listed as federally endangered or threatened in Chambers County, Texas:

Federally Listed Species for Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Birds	
Piping Plover	*Charadrius melodus*
Whooping Crane	*Grus americana*

Federally Listed Species for Chambers County by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD)	**Scientific Name**
Fish	
Smalltooth Sawfish	*Pristis pectinata*
Mammals	
Red Wolf Louisiana Black Bear	*Canis rufus* *Ursus americanus luteolus*
Reptiles	
Green Sea Turtle Kemp's Ridley Sea Turtle Leatherback Sea Turtle Loggerhead Sea Turtle Atlantic Hawksbill Sea Turtle	*Chelonia mydas* *Lepidochelys kempii* *Dermochelys coriacea* *Caretta caretta* *Eretmochelys imbricata*

EPA has determined that issuance of the proposed permit will have no effect on any of the ten (10) 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.

XI. 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 thoroughly reviewed, relied on, and adopted a cultural resource report prepared by Burns & McDonnell on behalf of ONEOK Hydrocarbon, L.P. ("ONEOK") submitted on April 8, 2014. Burns & McDonnell also prepared a previous cultural resource report submitted on April 18, 2013 for ONEOK which received concurrence from the Texas's State Historic Preservation Office (SHPO) on June 6, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 11 acres that includes the location of the proposed Frac-3 and Frac-4 expansion facility to be constructed at ONEOK's existing Mont Belvieu Natural Gas Liquids Fractionation Facility. Burns & McDonnell conducted a desktop review within a 1.0-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 field survey, no cultural resources were recorded within the APE. Based on the desktop review, five documented cultural resources were identified within 4.5-km of the APE; however, all of these sites were located outside the APE.

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 ONEOK will not affect properties potentially eligible for listing on the National Register.

On April 7, 2014, 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.

XII. 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.

XIII. Conclusion and Proposed Action

Based on the information supplied by ONEOK, our review of the analyses contained in 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 ONEOK Hydrocarbon, L.P. 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 365-day total, rolled daily, shall not exceed the following:

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
H-07 H-08 H-09 H-10 H-11 H-12	H-07 H-08 H-09 H-10 H-11 H-12	Hot Oil Heaters	CO_2	430,200[4]	430,648[4]	14.25 lbs CO_2/bbl y-grade feed for all heaters combined (365-day rolling average). Maintain an exhaust temperature of 385 °F or less for each heater (365-day rolling average). See permit conditions III.A.2.a. and b.
			CH_4	8.4[4]		
			N_2O	0.8[4]		
VENTS	H-07 H-08 H-09 H-10 H-11 H-12	Process Vents to Heaters	CO_2	30,000	30,003	Combustion of process vent gases in hot oil heaters. Quarterly gas analysis required. See permit conditions III.B.1.
			CH_4	0.13		
			N_2O	No Numerical Limit Established[5]		
FL-02 and MSS-FL-3	FL-02	Flare (Frac-3 and Frac-4 Contribution)	CO_2	5,044	5,250	Good combustion practices and flare gas recovery. See permit condition III.C.1.
			CH_4	8		
			N_2O	0.02		
FUG-04 FUG-05	FUG-04 FUG-05	Fugitive Process Emissions	CH_4	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of Enhanced LDAR Program. See permit conditions III.D.1.
CT-05 CT-06	CT-05 CT-06	Cooling Tower	CH_4	No Numerical Limit Established[7]	No Numerical Limit Established[7]	Leak detection/monthly monitoring of cooling water; heat exchanger repair. See permit condition III.E.1.
ENG-07	ENG-07	Emergency Air Compressor Engine	CO_2	28	28	Good combustion practices, non-emergency operation limited to 100 hrs./year See permit conditions III.F.1.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
ENG-08	ENG-08	Firewater Pump Engine	CO_2	29	29	Good combustion practices, non-emergency operation limited to 100 hrs./year See permit conditions III.F.1.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		
ENG-09	ENG-09	Emergency Generator Engine	CO_2	15	15	Good combustion practices, non-emergency operation limited to 100 hrs./year See permit conditions III.F.1.
			CH_4	No Numerical Limit Established[5]		
			N_2O	No Numerical Limit Established[5]		
ATM-MSS-03	MSS-FUG-03	MSS emissions to atmosphere from process vents	CH_4	No Numerical Limit Established[8]	No Numerical Limit Established[8]	Good Operational Practices - Minimize atmospheric venting emissions. See permit condition III.G.1
Totals[9]			**CO_2**	**465,316**	**CO_2e 466,049**	
			CH_4	**19.5**		
			N_2O	**0.82**		

1. Compliance with the annual emission limits (tons per year) is based on a 365-day total, rolled daily.
2. 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.
3. Global Warming Potentials (GWP): CH_4 = 25, N_2O = 298
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the hot oil heaters is for all six heaters combined (H-07, H-08, H-09, H-10, H-11 and H-12). The emissions for each heater shall not exceed 71,700 TPY CO_2, 1.4 TPY CH_4, and 0.1 TPY N_2O.
5. These emissions are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
6. Fugitive process emissions from EPN FUG-04 are estimated to be 0.50 TPY of CH_4, 0.0197 TPY CO_2, and 12.6 TPY CO_2e. Fugitive process emissions from EPN FUG-05 are estimated to be 0.50 TPY of CH_4, 0.0197 TPY CO_2, and 12.6 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
7. Cooling Tower emissions from EPN 5 are estimated to be 0.0136 TPY of CH_4, and 0.33 TPY CO_2e. Cooling Tower emissions from EPN 6 are estimated to be 0.013 TPY of CH_4, and 0.33 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
8. MSS emissions to the atmosphere are estimated to be 2 tpy CH_4 and 50 tpy CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
9. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.