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-106921-GHG

May 2013

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 September 21, 2012, 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 January 14, 2013. In connection with the same proposed modification, ONEOK submitted a minor NSR permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on November 14, 2012. The proposed project would expand operations at ONEOK's existing Mont Belvieu NGL Fractionation Plant by adding an additional 75,000 (nominal) barrel per day (bbl/day) fractionation plant (Frac-2) to process a demethanized natural gas mixture (Y-grade) into ethane, propane, isobutane, normal butane, and natural gasoline. 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 Gas 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.

II. Applicant

ONEOK Hydrocarbon, L.P.
100 West 5th Street
Tulsa, OK 74103

Physical Address:
11350 Fitzgerald Road
Baytown, TX 77523

Contact:
Terrie Blackburn
Manager, Regulatory Compliance ESH
ONEOK Hydrocarbons, L.P.
(918) 561-8052

III. 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

IV. 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

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

EPA concludes that ONEOK's application is subject to PSD review for the pollutant 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 CO_2e emissions of 212,523 tpy). 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.

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 equal or 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. Emission limits below the rates identified in (b)(23) must be in place prior to construction to ensure the validity of this applicability analysis and the source's authorization to construct a source of GHG emissions.

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.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow ONEOK to construct a new 75,000 (nominal) barrels per day (bbl/day) fractionation unit at the Mount Belvieu facility. The new Frac-2 unit 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 train includes: an amine contactor/amine regenerator for inlet gas treatment, a deethanizer, a depropanizer, a debutanizer, natural gasoline treatment, a deisobutanizer, post fractionation sulfur removal, and a number of process related utilities and ancillary operations. Each step in the process is described in detail below:

Inlet Gas Treatment

The Y-grade feedstock will be 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 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 it will be treated before being 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 will be catalytically converted in a reactor process. 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 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 three, 154 MMBtu/hr oil heaters. 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 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, the vapors will be routed to a FGRU.

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. Rather than sending all waste gases to the flare stack for combustion some of the vapors will be recovered and routed to the hot oil heaters as fuel via the flare gas recovery unit.

Cooling Tower

Various processes within the Frac-2 unit will require non-contact cooling water. A cooling tower is proposed for cooling and re-circulation of the necessary cooling water. Re-circulated 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-2 unit 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 pipeline. 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 Diesel Engines

Diesel engines will power emergency generators/air compressors and firewater pumps. Given that the actual configuration and sizing of this equipment may vary, the represented emissions cases include conservative, highest-possible 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 unit shutdown, vessel inspection, valve maintenance, rupture disk replacement, pump maintenance, gasket/bolt replacement, and instrumentation maintenance.

VII. General Format of the BACT Analysis

The BACT analyses for this draft permit are consistent with the statutory requirements of CAA sections 165(a)(4) and 169(3) and 40 CFR sections 52.21 (b)(12) and 52.21 (j). The analyses are also consistent 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

The majority of the GHG emissions associated with the proposed Frac-2 unit 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-04, H-05, and H-06)
- Process Vents (FIN: VENTS; EPNs: H-04, H-05, and H-06)
- Equipment Leak Fugitives (EPN: FUG-03)
- Cooling Towers (EPN: CT-04)
- Emergency Diesel Engines (EPNs: ENG-05 and ENG-06)
- Flare (EPN: FL-01)
- Maintenance, Start-up, and Shut-down (EPN: MSS-FUG-2)

IX. Hot Oil Heaters (EPNs: H-04, H-05, and H-06) 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 unit (Frac-2) will utilize three hot oil heaters each with a maximum firing rate of 154 MMBtu/hr. 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, and deisobutanizer. Flue gas from the hot oil heaters is treated with selective catalytic reduction (SCR) prior to being released to the atmosphere.

As part of the PSD review, ONEOK provides in the GHG permit application a 5-step top-down BACT analysis for the three heaters. EPA has reviewed ONEOK's BACT analysis for the heaters, 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

- 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)
  - Capture of CO_2
  - Transportation of captured CO_2 to a suitable storage location
  - Permanent storage of CO_2
- Use of Low-Carbon Fuels
  - Switching to lower carbon fuels to minimize CO_2 emissions

Carbon Capture and Storage (CCS)

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

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

2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for this type of application. Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed modification. However, the third approach, post-combustion capture, is available and applicable to heaters.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Once CO_2 is captured from the flue gas, the captured CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[2]

Step 2 – Elimination of Technically Infeasible Alternatives

All bulleted options identified in Step 1 are considered technically feasible for this project.[3] The only available and applicable CO_2 capture technology, post-combustion capture, is also believed to be technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Energy efficient design (10-15%)
- Energy efficient operation (10-15%)
- Use of low carbon fuel

CCS may be capable of achieving up to 90% reduction of produced CO_2 emissions in some circumstances and thus would be considered the most effective control method. ONEOK determined that the combination of all of the proposed energy efficient design and operating parameters will result in approximately a 10-15% reduction in GHG emissions in total. Natural gas was the intended fuel for the project so no additional reductions were identified for the use of lower-carbon fuel.

---

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

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

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

Carbon Capture and Storage

ONEOK provided a five-step top-down BACT analysis for CCS that provided the basis for eliminating the technology as a viable control option in step 4 of the BACT process based on economic costs and environmental impacts. ONEOK also provided a cost analysis to support its conclusion that the energy consumption of the CCS capture and transportation to injection systems would significantly increase the overall energy consumption of the plant, and would create additional CO_2 emissions (from amine solvent regeneration heaters) that would require further mitigation requirements. As explained more fully below, EPA has reviewed ONEOK's CCS analysis and has determined that CCS is not cost-effective at this time for this application and has negative environmental and energy impacts, which in combination support the elimination of CCS as BACT.

Based on ONEOK's cost analysis, the majority of the cost was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $15,140,000 per year for the three hot oil heaters. EPA Region 6 reviewed ONEOK's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project without CCS, which is estimated at $400,000,000. Based on a 20-year equipment life, this cost equates to an overall annualized cost of about $40,000,000 without CCS. The annualized cost of CCS would result in at least a 35% increase in this cost.

In addition, there would be additional negative environmental and energy impacts associated with use of CCS for the proposed heaters. The additional process equipment required to separate, cool, and compress the CO_2 would require significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy would be provided from additional combustion units, including heaters, engines, and/or combustion turbines. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or, if not captured, reduce the net amount of GHG emission reduction, making CCS even less cost effective. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, SO_2, and ammonia by as much as 30%. The proposed plant is located in an area of ozone non-attainment and the generation of additional NOx and VOC could have an adverse environmental impact.

Therefore, EPA has determined that CCS should be eliminated as BACT for this proposed modification due to the excessive economic impacts and negative environmental and energy impacts.

Energy Efficient Design, Energy Efficient Operating Practices, and Use of a Low Carbon Fuel

There are no expected adverse collateral energy, environmental, or economic impacts as a result of these measures proposed as BACT.

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

Company / Location	Process Description	BACT Control(s)	BACT Emission Limit / Requirements	Year Issued	Reference
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
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

* These permits are not issued as of 05/06/13.

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 three of the hot oil heaters combined. The Energy Transfer Partners, Lone Star NGL facility also proposed an output-based limit. The hot oil heaters at the Lone Star NGL facility have a heat input rate of 270 MMBtu/hr each. The hot oil heaters proposed by ONEOK have a heat input rate of 154 MMBtu/hr each, combined they have a heat input rate of 462 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 52% greater than each of Lone Star's hot oil heaters. The BACT limit proposed by ONEOK for all three 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 increased BACT 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. 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 71,760 tons CO_2e/year, based on a 365-day rolling average. Additionally, the three heaters shall have a combined, output based limit of 14.25 lb CO_2/barrel (bbl) of y-grade feed. This BACT limit 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 continuously 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 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions.

X. Process Vents (EPNs: H-04, H-05, and H-06) 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.

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)

<u>Carbon Capture and Storage</u>

Based on the determination discussed above in section IX that CCS is not cost-effective at this time for this application and has negative environmental and energy impacts, which in combination support the elimination of CCS as BACT, as, CCS will not be considered further in this BACT analysis for process vents.

Step 2 – Elimination of Technically Infeasible Alternatives

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 15,000 tons CO_2e/yr based on a 365-day rolling average. 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.

XI. Equipment Leak Fugitives (FUG-03) 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 11 tpy CO_2e. Fugitive emissions of methane account for less than 0.001% 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 28VHP 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 28VHP 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 28VHP program, with quarterly flange/connector monitoring. EPA concurs with ONEOK's assessment that using the TCEQ 28VHP[4] 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.

XII. Cooling Towers (CT-04) 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.

Step 1 – Identification of Potential Control Technologies

ONEOK identified only one available technology: leak detection through monthly monitoring of cooling water and the subsequent repair of any heat exchangers that have been determined to be leaking. EPA identified other available technologies.

- Cooling Tower Monitoring and Repair

[4] 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.

- Low Cycles of Concentration
- Acid and Blowdown Control
- Pretreatment of Make-up Water
- Once Through Seawater Cooling
- Air Cooling

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for once through seawater cooling. The proposed facility is not located adjacent to the ocean, therefore this control technology is considered technically infeasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

All of the remaining proposed technologies are intended to reduce PM and VOC emissions. The effectiveness of these technologies is not readily quantifiable.

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

<u>Cooling Tower Monitoring and Repair</u>

This technology consists of monthly monitoring of the cooling water to detect leaks, and subsequent repair of any exchangers that have been determined to be leaking. This technology does not have any negative economic, energy, or environmental impacts.

<u>Low Cycles of Concentration</u>

By using a higher rate of make-up water, the concentration of total dissolved solids in the recirculating water stream can be reduced. This reduces particulate matter in the cooling water drift. This technology has no impact on GHG emissions and would increase wastewater discharge. This approach is considered extremely wasteful of fresh water and therefore, this control technology is eliminated as BACT due to environmental impact.

<u>Acid and Blowdown Control</u>

By carefully controlling the acid addition and cooling tower water blowdown rate, the concentration of total dissolved solids in the recirculating stream can be reduced. This reduces particulate matter in the cooling water drift. It is uncertain that this technology would have any impact on the GHG emissions.

Pretreatment of Make-up Water

By pre-treating make-up water, the concentration of total dissolved solids in the recirculating water stream can be reduced. This reduces particulate matter in the cooling water drift. Pretreatment of the make-up water in a reverse osmosis system would require increasing the water pressure by several hundred psig. The additional power requirements would add about 2 MMBtu/hr of natural gas firing at the cogeneration facilities, increasing the GHG emissions. Therefore, pretreatment of the make-up water is rejected due to the overall increase in GHG emissions.

Air Cooling

By using air as a cooling medium, the recirculating cooling tower could be eliminated. However, any GHG leaks from heat exchangers would still leak into the air, and would be emitted at the same rate from equipment leak fugitives. In addition, using air cooling in this region would force distillation processes to be operated at higher temperatures and pressures. As a result, using air cooling would increase the firing rate of the hot oil heaters and would increase overall GHG emissions. Therefore, this control technology is eliminated based on environmental impacts.

Step 5 – Selection of BACT

ONEOK has proposed cooling tower monitoring and repair as BACT for the cooling tower. 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[5]. 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)[6]. Leak thresholds and timelines for repair will be consistent with the TCEQ air permit requirements for VOC emissions.

XIII. Emergency Diesel Engines (EPNs: ENG-05 and ENG-06) BACT Analysis

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

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

Step 1 – Identification of Potential Control Technologies

- Energy Efficient Design – Reduce the amount of fuel necessary by the use of Tier 3 efficient engines that are compliant with the non-road, compression ignition standards at 40 CFR 89.112.
- 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 all 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, 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 the remaining two options were evaluated together, 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 generators:

- Energy Efficient Design - ONEOK will install efficient Tier 3 design engines as found at 40 CFR § 89.112.
- Energy Efficient Operation
    - Initial engine tuning and testing.

- o Annual tune-ups to include changing the oil and filter, inspecting hoses and belts every 500 hours of operation or annually, whichever comes first.
- o 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 8 tpy CO_2e for the emergency generator engine and 35 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 as published on October 30, 2009 (74 FR 56395). 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.

XIV. Flare (EPN: FL-01) 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

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-2 process unit will be limited to 2,279 tons CO_2e/year based on a 365-day rolling average. The flow will be continuously 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 continuously monitored to maintain the minimum heating value necessary for flame stability. The presence of flame will be continuously 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 2,278 TPY CO_2e for EPN FL-01.

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).

XV. MSS Emissions (MSS-FUG-2) 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 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*
Fish	
Smalltooth Sawfish	*Pristis pectinata*

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**
Mammals	
Red Wolf	*Canis rufus*
Louisiana Black Bear	*Ursus americanus luteolus*
Reptiles	
Green Sea Turtle	*Chelonia mydas*
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*
Leatherback Sea Turtle	*Dermochelys coriacea*
Loggerhead Sea Turtle	*Caretta caretta*
Atlantic Hawksbill Sea Turtle	*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 relied on and adopted a cultural resource report prepared by Burns & McDonnell on behalf of ONEOK submitted on March 27, 2013.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 522 acres of land within and adjacent to the construction footprint of the existing facility. Burns & McDonnell conducted a reconnaissance survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of 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 desktop survey, no archaeological resources or historic structures were found within the APE. Based on the results of the reconnaissance survey, two residential historic-aged structures were identified within three hundred (300) feet of the APE. Both structures were determined to be not eligible for inclusion in the NHRP because: 1) it is not unique in architectural design, they were considered typical vernacular residences constructed through Texas in the mid-twentieth century and 2) they did not appear to meet any criteria of significance for inclusion in the NHRP. Additionally, several archaeological surveys, which included shovel testing, have been conducted in the area, five of which were within the boundaries of the APE. No cultural resource sites were identified to be eligible or potentially eligible for listing in the National Register as a result of those surveys.

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

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-04 H-05 H-06	H-04 H-05 H-06	Hot Oil Heaters	CO_2	215,100[4]	215,281[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	4.2[4]		
			N_2O	0.3[4]		
VENTS	H-04 H-05 H-06	Process Vents to Heaters	CO_2	15,000	15,001	Combustion of process vent gases in hot oil heaters. Quarterly gas analysis required. See permit conditions III.B.1.
			CH_4	0.061		
			N_2O	No Numerical Limit Established[5]		
FL-01	FL-01	Flare (Frac-2 Contribution)	CO_2	2,236	2,278	Good combustion practices and flare gas recovery. See permit condition III.C.1.
			CH_4	2		
			N_2O	No Numerical Limit Established[5]		
FUG-03	FUG-03	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-04	CT-04	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.

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
ENG-05	ENG-05	Generator	CO_2	8	8.0	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-06	ENG-06	Firewater Pump Engine	CO_2	35	35.0	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-02	MSS-FUG-02	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**	**232,379**	**CO_2e 232,635**	
			CH_4	**7.8**		
			N_2O	**0.3**		

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 = 21, N_2O = 310
4. The GHG Mass Basis TPY limit and the CO_2e TPY limit for the hot oil heaters is for all three heaters combined (HY-04, H-05, and H-06). 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. The 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-03 are estimated to be 0.50 TPY of $CH_{4,}$ 0.02 TPY CO_2, and 10.6 TPY CO_2e.
7. Cooling Tower emissions from EPN CT-04 are estimated to be 0.016 TPY of $CH_{4,}$ and 0.34 TPY CO_2e.
8. MSS emissions to the atmosphere are estimated to be 1 tpy CH_4 and 21tpy CO_2e.
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.