# PREVENTION OF SIGNIFICANT DETERIORATION PERMIT FOR GREENHOUSE GAS EMISSIONS ISSUED PURSUANT TO THE REQUIREMENTS AT 40 CFR § 52.21

**U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION 6**

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| **PSD PERMIT NUMBER:** | PSD-TX-1396-GHG |
| **PERMITTEE:** | ONEOK Hydrocarbon, L.P.<br>100 West 5th Street<br>Tulsa, OK 74103 |
| **FACILITY NAME:** | ONEOK Hydrocarbon<br>Mont Belvieu NGL Fractionation Plant |
| **FACILITY LOCATION:** | 11350 Fitzgerald<br>Baytown, TX 77523 |

Pursuant to the provisions of the Clean Air Act (CAA), Subchapter I, Part C (42 U.S.C. Section 7470, *et. Seq.*), and the Code of Federal Regulations (CFR) Title 40, Section 52.21, and the Federal Implementation Plan at 40 CFR § 52.2305 (effective May 1, 2011 and published at 76 FR 25178), the U.S. Environmental Protection Agency, Region 6 is issuing a *Prevention of Significant Deterioration* (PSD) permit to ONEOK Hydrocarbon, L.P. for Greenhouse Gas (GHG) emissions. The Permit authorizes the construction of a third and fourth fractionation train at the existing Mont Belvieu Natural Gas Liquids (NGL) Fractionation Plant located in Mont Belvieu, Texas.

ONEOK Hydrocarbon, L.P. is authorized to construct a third and fourth fractionation train (Frac-3 and Frac-4) at the existing NGL processing plant as described herein, in accordance with the permit application (and plans submitted with the permit application), the federal PSD regulations at 40 CFR § 52.21, and other terms and conditions set forth in this PSD permit in conjunction with the corresponding Texas Commission on Environmental Quality (TCEQ) NSR Permit Nos. PSDTX1396, and N198. Failure to comply with any condition or term set forth in this PSD Permit may result in enforcement action pursuant to Section 113 of the Clean Air Act (CAA). This PSD Permit does not relieve ONEOK Hydrocarbon, L.P. of the responsibility to comply with any other applicable provisions of the CAA (including applicable implementing regulations in 40 CFR Parts 51, 52, 60, 61, 72 through 75, and 98) or other federal and state requirements (including the state PSD program that remains under approval at 40 CFR § 52.2303).

In accordance with 40 CFR §124.15(b), this PSD Permit becomes effective 30 days after the service of notice of this final decision unless review is requested on the permit pursuant to 40 CFR §124.19.

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Wren Stenger, Director
Multimedia Planning and Permitting Division

Date

**ONEOK Hydrocarbon, L.P. (PSD-TX-1396-GHG)**
**Prevention of Significant Deterioration Permit**
**For Greenhouse Gas Emissions**
**Draft Permit Conditions**





## PROJECT DESCRIPTION

Pursuant to the provisions of this permit, the facility will construct two (2) additional 75,000 (nominal) barrel/day fractionation trains (Frac-3 and Frac-4) at the existing Mont Belvieu NGL Fractionation Plant. The Frac-3 and Frac-4 trains will fractionate Y-Grade natural gas liquids (NGL) into constituent products, including ethane, propane, isobutane, normal butane, and natural gasoline.

The Y-grade feedstock first will be piped to an amine contactor where $CO_2$ and $H_2S$ will be removed, per customer specifications. The rich amine solution will be directed to the amine regenerator where the $CO_2$ and $H_2S$ will be stripped and the lean amine recycled back to the contactor.

Frac-3 and Frac-4 will utilize a hot oil system to supply heat to the system. By using hot oil, heat can be efficiently transferred to the fractionation process with a minimum loss of heat to the oil, allowing for a quicker recovery to the desired temperature in a closed-loop system. ONEOK plans to utilize the hot oil system as needed to provide heat in the amine regeneration unit and as needed to various heat exchangers associated with the fractionation process (i.e., piping to maintain desired temperatures on process streams). The facility expansion will add six 154 MMBtu/hr hot oil heaters. The heaters will be primarily natural gas-fired. The natural gas will be supplemented with vent streams from various process units. The vent stream from the amine regenerators will be piped directly to the plant's heaters and combusted. Flash gas from the amine regenerators 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. Flue gas from the heaters will be treated with Selective Catalytic Reduction (SCR) to reduce NOx emissions. Vent gases which cannot be recovered in the FGRU and combusted in the heaters will be combusted in the flare.

Fugitive emissions of GHG pollutants, including $CO_2$ and methane, may result from piping equipment leaks. However, very little of these pollutants are contained in the NGL after the amine unit. The piping components that may leak include valves, flanges, pump seals, etc. ONEOK will implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the two additional fractionation trains (Frac-3 and Frac-4).

**EQUIPMENT LIST**

The following devices are subject to this GHG PSD permit:

| Federal Identification Number | Emission Point Number | Description |
|---|---|---|
| H-07<br>H-08<br>H-09<br>H-10<br>H-11<br>H-12 | H-07<br>H-08<br>H-09<br>H-10<br>H-11<br>H-12 | Six Hot Oil Heaters (Combustion Unit) rated at 154 MMBtu/hr each. |
| VENTS-3 | H-07<br>H-08<br>H-09<br>H-10<br>H-11<br>H-12 | Frac-3 and Frac-4 Process Vents to Heaters |
| FL-02 and MSS-FL-3 | FL-01/FL-02 | Flare (Combustion Unit – Frac-3 and Frac-4 contribution) |
| CT-05 | CT-05 | Frac-3 Cooling Tower |
| CT-06 | CT-06 | Frac-4 Cooling Tower |
| ENG-07 | ENG-07 | Frac-3 and Frac-4 Emergency Air Compressor |
| ENG-08 | ENG-08 | Frac-3 and Frac-4 Firewater Pump |
| ENG-09 | ENG-09 | Frac-3 and Frac-4 Emergency Generator |
| FUG-04 | FUG-04 | Fugitive Emissions from the Frac-3 Train |
| FUG-05 | FUG-05 | Fugitive Emissions from the Frac-4 Train |
| ATM-MSS-3 | MSS-FUG-3 | MSS Degassing (Frac-3 and Frac-4 Contribution) |

## I. GENERAL PERMIT CONDITIONS

### A. PERMIT EXPIRATION

As provided in 40 CFR §52.21(r), this PSD Permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR §52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Pursuant to 40 CFR §52.21(r), EPA may extend the 18-month period upon a written satisfactory showing that an extension is justified.

### B. PERMIT NOTIFICATION REQUIREMENTS

Permittee shall notify EPA Region 6 in writing or by electronic mail of the:

1. date construction is commenced, postmarked within 30 days of such date;

2. actual date of initial startup, as defined in 40 CFR §60.2, postmarked within 15 days of such date; and

3. date upon which initial performance tests will commence, in accordance with the provisions of Section V, postmarked not less than 30 days prior to such date. Notification may be provided with the submittal of the performance test protocol required pursuant to Condition V.B.

### C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

## D. MALFUNCTION REPORTING

1. Permittee shall notify EPA by mail within 48 hours following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in GHG emissions above the allowable emission limits stated in Section II of this permit.

2. Within 10 days of the restoration of normal operations after any failure described in I.D.1., Permittee shall provide a written supplement to the initial notification that includes a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Section II and III, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

## E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

## F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed, this PSD Permit shall be binding on all subsequent owners and operators. Permittee shall notify the succeeding owner and operator of the existence of the PSD Permit and its conditions by letter; a copy of the letter shall be forwarded to EPA Region 6 within thirty days of the letter signature.

## G. SEVERABILITY

The provisions of this PSD Permit are severable, and, if any provision of the PSD Permit is held invalid, the remainder of this PSD Permit shall not be affected.

## H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

Permittee shall construct and operate this project in compliance with this PSD Permit, the application on which this permit is based and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

# I. ACRONYMS AND ABBREVIATIONS

| | |
|---|---|
| BACT | Best Available Control Technology |
| bbl | Barrel |
| Btu | British Thermal Unit |
| CAA | Clean Air Act |
| CEMS | Continuous Emissions Monitoring System |
| CFR | Code of Federal Regulations |
| CGA | Cylinder Gas Audit |
| $CH_4$ | Methane |
| $CO_2$ | Carbon Dioxide |
| $CO_2e$ | Carbon Dioxide Equivalent |
| DRE | Destruction and Removal Efficiency |
| dscf | Dry Standard Cubic Foot |
| EPN | Emission Point Number |
| FR | Federal Register |
| GHG | Greenhouse Gas |
| gr | Grains |
| HHV | High Heating Value |
| hp | Horsepower |
| Hr | Hour |
| IFR | Internal Floating Roof |
| LDAR | Leak Detection and Repair |
| LHV | Lower Heating Value |
| Lb | Pound |
| MMBtu | Million British Thermal Units |
| MMSCFD | Million Standard Cubic Feet per Day |
| MSS | Maintenance, Start-up and Shutdown |
| NGL | Natural Gas Liquids |
| $N_2O$ | Nitrous Oxides |
| NSPS | New Source Performance Standards |
| PSD | Prevention of Significant Deterioration |
| QA/QC | Quality Assurance and/or Quality Control |
| RATA | Relative Accuracy Test Audit |
| SCFH | Standard Cubic Feet per Hour |
| SCR | Selective Catalytic Reduction |
| TAC | Texas Administrative Code |
| TCEQ | Texas Commission on Environmental Quality |
| TO | Thermal Oxidizer |
| TPY | Tons per Year |
| VRU | Vapor Recovery Unit |
| USC | United States Code |

## II. 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<br>H-08<br>H-09<br>H-10<br>H-11<br>H-12 | H-07<br>H-08<br>H-09<br>H-10<br>H-11<br>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. |
| | | | $CH_4$ | 8.40[4] | | |
| | | | $N_2O$ | 0.8[4] | | |
| VENTS-3 | H-07<br>H-08<br>H-09<br>H-10<br>H-11<br>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<br>FUG-05 | FUG-04<br>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<br>CT-06 | CT-05<br>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] | | |
| 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] | | |

| FIN | EPN | Description | GHG Mass Basis | | TPY $CO_2e$[2,3] | BACT Requirements |
|---|---|---|---|---|---|---|
| | | | | TPY[2] | | |
| ENG-09 | ENG-09 | Emergency Generator Engine | $CO_2$ | 15 | 15 | Good combustion practices, non-emergency operation limited to 100 hrs./year<br>See permit conditions III.F.1. |
| | | | $CH_4$ | No Numerical Limit Established[5] | | |
| | | | $N_2O$ | No Numerical Limit Established[5] | | |
| ATM-MSS-3 | MSS-FUG-3 | 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** | **466,049 $CO_2e$** | |
| | | | **$CH_4$** | **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 71,765 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.

## III. Special Permit Conditions

### A. Requirements for Heaters (EPNs: H-07, H-08, H-09, H-10, H-11, and H-12)

#### 1. Work Practice and Operational Requirements

a. The Frac-3 and Frac-4 trains have a total of six hot oil heaters; with each hot oil heater rated at 154 million British thermal units per hour (MMBtu/hr). Flue gas from the heaters will be treated with Selective Catalytic Reduction (SCR) technology prior to release to the atmosphere and the heaters shall be equipped with low NOx burners.
b. Permittee shall calculate, on a daily basis, the amount of $CO_2$ emitted from combustion of natural gas in tons/yr using the equation at 40 CFR 98.33(a)(2)(i). Compliance shall be based on a 365-day rolling total.
c. Permittee shall calculate the $CH_4$ and $N_2O$ emissions on a 365-day rolling basis. Permittee shall determine compliance with the $CH_4$ and $N_2O$ emissions limits contained in this section using the default $CH_4$ and $N_2O$ emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98 and the measured actual heat input (HHV).
d. Permittee shall calculate the $CO_2e$ emissions on a 365-day rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1.
e. Primary fuel for the heaters shall be limited to pipeline quality natural gas with a fuel sulfur content of up to 5 grains of sulfur per 100 dry standard cubic feet (gr S/100 dscf). The fuel gross calorific value (GCV) [high heat value (HHV)] of the fuel shall be determined, at a minimum, semiannually by the procedures contained in 40 CFR Part 98.34(a)(6) and records shall be maintained of the semiannual fuel GCV for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the heaters or shall allow a sample to be taken by EPA for analysis.
f. Combustion of process vent gases as a fuel shall be permitted in accordance with Condition III.B.1.
g. Combustion of recovered flare gas shall be permitted in accordance with Condition III.C.1.c.
h. The flow rate of the fuel combusted in natural gas-fired combustion emission units identified in this section shall be measured and recorded using an operational non-resettable elapsed flow meter at each inlet. The flow meters shall be calibrated on an annual basis. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer.

i. Oxygen analyzers shall continually monitor and record oxygen concentration in the hot oil heaters. The oxygen readings shall be reduced to an averaging period of 6 minutes or less and record it at that frequency.

j. A relative accuracy test audit (RATA) of the stack $O_2$ analyzer is required once every four quarters in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.1.

k. The oxygen analyzers shall be quality-assured at least quarterly using cylinder gas audits (CGAs) in accordance with 40 CFR Part 60, Appendix F, Procedure 1, § 5.1.2.

l. The permittee shall install $O_2$ instrumentation in the firebox and stack. Oxygen in the combustion chamber of the heaters shall not exceed 15% except during periods of maintenance, startup, or shutdown.

m. The heaters shall be tuned for thermal efficiency on an annual basis.

n. The Permittee shall conduct preventive maintenance per manufacturer's guidelines, as well as regular visual inspections to reduce air leakage

o. The heaters are not expected to have GHG emissions in excess of the allowed emission rates during periods of startup, shutdown, or maintenance. The fuel firing rates will be below the maximum rate authorized for normal operations.

**2. Heater BACT Emission Limits**

a. On or after the date of initial startup, the Permittee shall not discharge or cause the combined discharge of emissions from all six of the hot oil heaters (H-07, H-08, H-09, H-10, H-11 and H-12) in excess of 14.25 lbs $CO_2$/barrel (bbl - a barrel contains 42 gallons) of NGL processed on a 365-day rolling average. This limit only applies to the combustion of natural gas and recovered flare gas in the hot oil heater burners. To determine achievement of this BACT emission limit, the Permittee shall divide the value of the measured input mass rate of $CO_2$ from the natural gas GCV analysis required in Special Condition III.A.1.e. by the measured daily natural gas liquids processed from the Frac-3 and Frac-4 units (bbl) required in Special Condition IV.B.

b. Permittee shall continually monitor and record the hot oil heaters exhaust temperature hourly and limit the temperature to less than or equal to 385 $^{o}$F on a 365-day rolling average basis. This stack temperature is for normal operations and does not include startup, shutdown, and MSS activities.

## B. Requirements for Process Vent Gases (EPNs: H-07, H-08, H-09, H-10, H-11, and H-12)

### 1. Work Practice and Operational Requirements

a. The Permittee shall route process vent gases from the amine regenerator vents, and other process vents, to the hot oil heaters (EPNs: H-07, H-08, H-09, H-10, H-11 and H-12) for combustion as a fuel source.

b. The Permittee shall continually measure the flow of process vent gases to hot oil heaters using an operational non-resettable elapsed flow meter. A computer that collects, sums, and stores electronic data from continuous fuel flow meters is an acceptable totalizer. The emissions from combustion shall be recorded and monitored separate from the combustion of natural gas in the hot oil heater.

c. The Permittee shall perform weekly analyses of the process vent gas for carbon content, high heating value (HHV), and molecular weight in accordance with 40 CFR 98.33(a)(2)(ii).

d. The Permittee shall calculate the GHG volumetric emissions of $CO_2$ and $CH_4$ using the equations at 40 CFR 98. 33(a)(3)(iii). Permittee shall determine compliance with the $CH_4$ and $N_2O$ emissions limits contained in this section using the default $CH_4$ and $N_2O$ emission factors contained in Table C-2 and equation C-9a of 40 CFR Part 98. The Permittee shall use the flow as measured according to Condition III.B.1.b. and the process vent gas HHV as determined according to Condition III.B.1.c.

e. Permittee shall calculate the $CO_2e$ emissions on a 12-month rolling basis, based on the procedures and Global Warming Potentials (GWP) contained in Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. The record shall be updated by the last day of the following month.

f. The Permittee shall maintain records necessary to demonstrate compliance with the emission limit on a 365-day average, rolling daily.

g. On or after initial startup the Permittee shall not discharge or cause the discharge of emissions in excess of 30,003 tons of $CO_2e$/year from the combustion of process vent gases.

## C. Flare Emission Sources (EPN: FL-02)

### 1. Work Practice and Operational Requirements

a. MSS emissions, including process vent streams and vapors from relief valves, from the proposed Frac-3 and Frac-4 trains shall be vented to a flare header when feasible. MSS emissions may be vented to the atmosphere as identified in condition III.G.1.

b. The Permittee shall install and operate a Flare Gas Recovery Unit. The flare (FL-02) shall only combust pilot gas (natural gas) and sweep gas during normal operations.
c. The recovered flare gas shall be routed to the hot oil heaters (EPNs: H-07, H-08, H-09, H-10, H-11 and H-12) to be used as a fuel source.
d. The Permittee shall continually measure the flow of recovered gases to hot oil heaters using the operational non-resettable elapsed flow meter as identified in condition III.B.1.b.
e. The flare shall have a minimum destruction and removal efficiency (DRE) for methane of 99% based on flow rate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).
f. The flare shall be air assisted.
g. The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity, and pilot flame monitoring. An infrared monitor is considered equivalent to a thermocouple for flame monitoring purposes.
h. On or after initial startup, the Permittee shall not discharge or cause the discharge of emissions in excess of 5,250 tons $CO_2e$/year, based on a 365-day rolling average.
i. Flare header flow meter will measure flow at least once each 15 minutes. The flow meter shall be calibrated or certified at least biannually.
j. The flare shall be equipped with a gas composition analyzer. The analyzer shall measure the gas composition at least once per hour and be calibrated monthly.
k. The flow meter and analyzers used for flare compliance shall be operational at least 95% of the time when waste gases are directed to the flare for control.
l. Permittee must record the time, date, HHV in MMBtu/hr and duration of each MSS event resulting in flaring. The records must include hourly $CH_4$ emission levels as measured by the in-line gas analyzer (Gas chromatograph or equivalent with volumetric stack gas flow rate) and the calculations based on the actual heat input for the $CO_2$, $N_2O$, and $CH_4$ emissions during each MSS event. Process knowledge and engineering calculations are acceptable if the in-line gas analyzer is not operational during the MSS event. These records must be kept for five years following the date of each event.
m. $CO_2$ emissions are calculated using equation Y-1 found in 40 CFR Part 98 Subpart Y, §98.253(b)(1)(ii)(A). $CH_4$ and $N_2O$ emissions are calculated using equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y.

n. $CO_2$ emissions are calculated using equation Y-1 found in 40 CFR Part 98 Subpart Y, §98.253(b)(1)(ii)(A). $CH_4$ and $N_2O$ emissions are calculated using equations Y-4 and Y-5 as found in 40 CFR Part 98 Subpart Y.
o. Compliance with the annual emission limit shall be determined on a 365-day total, rolled daily.

**D. Fugitive Emission Sources (EPN: FUG-04 and FUG-05)**

**1. Fugitive Emission Sources Work Practice and Operational Requirements**

The Permittee shall implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program and shall conduct quarterly monitoring of flanges and connectors for fugitive emissions from streams containing greater than 10% methane by volume.

**E. Cooling Tower (EPN: CT-05 and CT-06)**

**1. Cooling Tower Work Practice and Operational Requirements**

a. The methane emissions associated with each cooling tower shall be monitored monthly with an air stripping system meeting the requirements of the TCEQ Sampling Procedures Manual, Appendix P (dated January 2003 or a later edition) or an approved equivalent sampling method as specified in the TCEQ Permit No. 106921. The results of the monitoring, cooling water flow rate, and maintenance activities on the cooling water system shall be recorded.
b. The Permittee shall maintain records of cooling tower monitoring and corrective actions taken.

**F. Emissions from Emergency Engines (EPNs: ENG-07, ENG-08, and ENG-09)**

**1. Emergency Air Compressor Engine Work Practice and Operational Requirements**

a. The Emergency Air Compressor Engine (ENG-07) shall fire diesel fuel containing no more than 0.0015 percent sulfur by weight.
b. The Permittee shall implement good combustion practices, including annual tune-ups and preventive maintenance per manufacturer's recommendations.
c. Non-emergency use of each engine shall be limited to 100 hours per year.
d. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Emergency Generator, including, but not limited to, the following: all records or reports pertaining to maintenance

performed, all records relating to performance tests and monitoring of the emergency generator equipment; fuel heat input values; and hours of operation required in Special Condition III.F.1.c.; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.

e. The Diesel Fired Fire Water Pumps, Diesel Fired Emergency Generators, and Emergency Air Compressors shall meet the monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
f. On or after initial startup, the Permittee shall not discharge or cause the discharge of emissions in excess of 28.24 tons $CO_2e$/year, based on a 365-day rolling average for non-emergency use.
g. The Permittee shall demonstrate compliance with the 365-day rolling average emission limit by using the calculations at 40 CFR Part 98, Subpart C.

**2. Emergency Firewater Pump Engine Work Practice and Operational Requirements**

a. The Emergency Firewater Pump Engine (ENG-08) shall fire diesel fuel containing no more than 0.0015 percent sulfur by weight.
b. The Permittee shall implement good combustion practices, including annual tune-ups and preventive maintenance per manufacturer's recommendations.
c. Non-emergency use of each engine shall be limited to 100 hours per year.
d. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Emergency Generator, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator equipment; fuel heat input values; and hours of operation required in Special Condition III.F.2.c.; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
e. The Diesel Fired Fire Water Pumps, Diesel Fired Emergency Generators, and Emergency Air Compressors shall meet the monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart IIII, Standards of Performance for Stationary Compression Ignition Internal Combustion Engines.
f. On or after initial startup, the Permittee shall not discharge or cause the discharge of emissions in excess of 28.69 tons $CO_2e$/year, based on a 365-day rolling average for non-emergency use.

g. The Permittee shall demonstrate compliance with the 365-day rolling average emission limit by using the calculations at 40 CFR Part 98, Subpart C.

### 3. Emergency Generator Engine Work Practice and Operational Requirements

a. The Emergency Generator Engine (ENG-09) shall fire natural gas.
b. The Permittee shall implement good combustion practices, including annual tune-ups and preventive maintenance per manufacturer's recommendations.
c. Non-emergency use of each engine shall be limited to 100 hours per year.
d. Permittee shall maintain a file of all records, data measurements, reports and documents related to the operation of the Emergency Generator, including, but not limited to, the following: all records or reports pertaining to maintenance performed, all records relating to performance tests and monitoring of the emergency generator equipment; fuel heat input values; and hours of operation required in Special Condition III.F.3.c.; and all other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than five years following the date of such measurements, maintenance, reports, and/or records.
e. The Emergency Generator shall meet the applicable monitoring and recordkeeping requirements as required in 40 CFR Part 60 Subpart JJJJ, Standards of Performance for Stationary Spark Ignition Internal Combustion Engines.
f. On or after initial startup, the Permittee shall not discharge or cause the discharge of emissions in excess of 15.47 tons $CO_2e$/year, based on a 365-day rolling average for non-emergency use.
g. The Permittee shall demonstrate compliance with the 365-day rolling average emission limit by using the calculations at 40 CFR Part 98, Subpart C.

## G. Emissions from MSS Activities to Atmosphere (EPN: MSS-FUG-03)

### 1. MSS Work Practice and Operational Requirements

a. MSS emissions shall be minimized through the implementation of good operational practices, including venting gases purged from process vessels to the flare gas recovery unit (FGRU) when possible.
b. When possible, venting to the atmosphere shall occur only when the hydrocarbon concentration in process vessels is below 10,000 ppmv, as determined by a Lower Explosive Limit (LEL) meter or Organic Vapor Analyzer.
c. Records of each MSS activity that results in direct venting of emissions to the atmosphere shall be maintained to include the date, time, and duration of each MSS event.

d. For MSS emissions that are released to atmosphere, the Permittee shall also include a record of the hydrocarbon concentration as measured by the LEL meter or Organic Vapor Analyzer with the records required in III.G.1.c.

## H. Continuous Emissions Monitoring Systems (CEMS)

1. As an alternative to Special Conditions III.A.1.b and III.B.1.d., Permittee may install a $CO_2$ CEMS and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording $CO_2$ emissions discharged to the atmosphere, and use these values to show compliance with the annual emission limit in Table 1.
2. Permittee shall ensure that all required $CO_2$ monitoring system/equipment are installed and all certification tests are completed on or before the earlier of 90 unit operating days or 180 calendar days after the date the unit commences operation.
3. Permittee shall ensure compliance with the specifications and test procedures for $CO_2$ emission monitoring system at stationary sources, 40 CFR Part 75, or 40 CFR Part 60, Appendix B, Performance Specification numbers 1 through 9, as applicable.
4. Permittee shall meet the appropriate quality assurance requirements specified in 40 CFR Part 60, Appendix F for the $CO_2$ emission monitoring system.

# IV. Recordkeeping Requirements

A. In order to demonstrate compliance with the GHG emission rates, Permittee will monitor the following parameters and summarize the data on a calendar month basis.

  a. Operating hours for the emergency engines;
  b. The natural gas fuel usage for all combustion sources, using continuous fuel flow monitors (a group of equipment can utilize a common fuel flow meter, as long as actual fuel usage is allocated to the individual equipment based upon actual operating hours and maximum firing rate);
  c. Annual fuel sampling for natural gas, quarterly fuel sampling of vent gas; and
  d. The daily natural gas liquids processing rate for the Frac-3 and Frac-4 units.

B. Permittee shall maintain the daily production volumes of natural gas liquids fed to the Frac-3 and Frac-4 units in barrels per day (bbl/day). Records shall be maintained for a period of five years.

C. Permittee will implement the TCEQ 28LAER leak detection and repair (LDAR) program and keep records of the monitoring results, as well as the repair and maintenance records.

D. At least once per quarter, the Permittee will obtain an updated analysis of the vent gas from the amine units routed directly to the hot oil heaters. These analyses will be considered to be representative of the gas streams for the quarter during which it was taken and will be used to estimate the amine units waste gas vent emissions, Higher Heating Value (HHV), and Lower Heating Value (LHV).

E. For each calendar month, the Permittee will calculate the 12 month rolling GHG emission rates for comparison to the emission limits in Table 1.

F. The Permittee will also maintain site-specific procedures for preventative maintenance practices and vendor-recommended operating procedures and O&M manuals. These manuals shall be maintained with the permit and located on-site.

G. Permittee shall maintain records of the following for GHG emissions from the Equipment List (excluding fugitives): all records or reports pertaining to significant maintenance performed; duration of startup, shutdown; the initial startup period for the emission units; malfunctions; all records relating to performance tests, calibrations, checks, and monitoring of combustion equipment; duration of an inoperative monitoring device and emission units with the required corresponding emission data; and all other information required by this permit recorded in a permanent form suitable for inspection. These records may be maintained in electronic databases. The Permittee shall provide the records upon request by the Agency or authorized representative.

H. Records related to fugitive emissions must be maintained to meet the requirements of the TCEQ 28LAER LDAR Program. The Permittee shall provide the records upon request by the Agency or authorized representative.

I. Permittee shall maintain records and submit a written report of all excess emissions to EPA semi-annually, except when: more frequent reporting is specifically required by an applicable subpart; or the Administrator or authorized representative, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:
   1. Time intervals, data and magnitude of the excess emissions, the nature and cause (if known), corrective actions taken and preventive measures adopted;
   2. Applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);
   3. A statement in the report of a negative declaration; that is; a statement when no excess emissions occurred or when the monitoring equipment has not been inoperative, repaired or adjusted; and
   4. Any failure to conduct any required source testing, monitoring, or other compliance activities.

J. Excess emissions shall be defined as any period in which the facility emission exceeds a maximum emission limit set forth in this permit.

K. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.
L. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

## V. Performance Testing Requirements:

A. The Permittee shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units H-07, H-08, H-09, H-10, H-11, and H-12 to determine the initial compliance with the $CO_2$ emission limits established in this permit. Sampling shall be conducted in accordance with 40 CFR § 60.8 and EPA Method 3a or 3b for the concentration of $CO_2$ for the heaters.

    1. Multiply the $CO_2$ hourly average emission rate determined under maximum operating test conditions by 8,760 hours, and adjust by the ratio of permitted annual average firing rate to the permitted maximum hourly firing rate.
    2. If the above calculated $CO_2$ emission total does not exceed the tons per year (TPY) specified on Table 1, no compliance strategy needs to be developed.
    3. If the above calculated $CO_2$ emission total exceeds the tons per year (TPY) specified in Table 1, the facility shall;
        a. Document the exceedence in the test report; and
        b. Explain within the report how the facility will assure compliance with the $CO_2$ emission limit listed in Table 1.

B. Within 60 days after achieving the maximum production rate at which the affected facility will be operated, but not later than 180 days after initial startup of the facility, performance tests(s) shall be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by EPA.
C. Permittee shall submit a performance test protocol to EPA no later than 30 days prior to the test to allow review of the test plan and to arrange for an observer to be present at the test. The performance test shall be conducted in accordance with the submitted protocol, and any changes required by EPA.
D. Performance testing shall be conducted using a representative rate of operation.
E. Fuel sampling for the process vent gases, and emission units H-07, H-08, H-09, H-10, H-11, and H-12 shall be conducted in accordance with 40 CFR Part 98.
F. Performance tests shall be conducted under such conditions to ensure representative performance of the affected facility. The Permittee shall make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

G. The owner or operator shall provide the EPA at least 30 days prior notice of any performance test, except as specified under other subparts, to afford the EPA the opportunity to have an observer present and/or to attend a pre-test meeting. If there is a delay in the original test date, the Permittee shall provide at least 7 days prior notice of the rescheduled date of the performance test.

H. The Permittee shall provide, or cause to be provided, performance testing facilities as follows:

1. Sampling ports adequate for test methods applicable to this facility,
2. Safe sampling platform(s),
3. Safe access to sampling platform(s), and
4. Utilities for sampling and testing equipment.

I. Unless otherwise specified in this permit, each performance test shall consist of three separate runs using the applicable test method. Each run shall be conducted under the conditions specified in the applicable test method. For purposes of determining compliance with an applicable test method, the arithmetic mean of the results of the three runs shall apply.

J. Emissions testing, as outlined above, shall be performed every three years, or more frequently if identified above, to verify continued performance at permitted emission limits.

**VI. Agency Notifications**

Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Multimedia Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6 PD-R)
Dallas, TX  75202
Email:  Group R6AirPermits@EPA.gov

Permittee shall submit a copy of all compliance and enforcement correspondence as required by this Approval to Construct to:

Compliance Assurance and Enforcement Division
EPA Region 6
1445 Ross Avenue (6EN)
Dallas, TX  75202