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

PSD PERMIT NUMBER: PSD-TX-110274-GHG

PERMITTEE: Lone Star NGL Fractionators, LLC
800 E. Sonterra Blvd., Suite 400
San Antonio, TX 78258

FACILITY NAME: Lone Star NGL, FRACIII Gas Plant

FACILITY LOCATION: 9850 FM 1942
Baytown, TX 77521

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 for the Lone Star NGL FRAC III Plant for Greenhouse Gas (GHG) emissions. The Permit authorizes the construction of a natural gas liquids processing plant (FRAC III Plant) at the existing Mont Belvieu Gas Plant located in Mont Belvieu, Texas.

Lone Star NGL Fractionators is authorized to construct a natural gas liquids (NGL) processing plant (FRAC III Plant) and associated equipment at the Mont Belvieu Gas 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) minor new source review (NSR) permit No. 110274 and non attainment new source review (NNSR) permit No. N182. 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 Lone Star NGL Fractionators 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.

_________________________________ _______________________

Wren Stenger, Director — Date
Multimedia Planning and Permitting Division

Lone Star NGL Fractionators LLC
Mont Belvieu FRAC III Gas Plant (PSD-TX-110274-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 a natural gas liquids (NGL) processing plant (FRAC III Plant) at the Mont Belvieu Gas Plant in Chambers County, Texas. The Site currently includes two NGL processing plants (FRAC I Plant and FRAC II Plant). The three NGL processing plants (FRAC I Plant, FRAC II Plant, and FRAC III Plant) are operationally independent of each other. Therefore, this GHG PSD air permit addresses FRAC III Plant GHG emissions only. FRAC III Plant will fractionate Y-grade natural gas liquids (NGL) through a series of trayed columns that separate the NGL into constituent gas products, which include ethane, propane, butanes, and natural gasoline, for sale to customers. FRAC III Plant will process approximately 100,000 barrels per day.

The NGL feed will enter the FRAC III Plant and pass through a closed loop amine unit. The amine unit contactors will remove CO_2 and H_2S impurities from the NGL stream. Waste gas from the amine unit will be routed to the thermal oxidizer (TO) for combustion of H_2S and VOC. From the Amine Unit, the NGL will be routed through a Molecular Sieve dehydration unit, where the water content of the NGL will be reduced. The Molecular Sieve will not have vents to the atmosphere. The only GHG emissions from the Molecular Sieve will be fugitive piping equipment leaks. From the Molecular Sieve dehydration unit, the NGL will be fed to a series of trayed columns for separation into constituent product gases. No GHG emissions will be generated from processes downstream from the Amine Unit, except for emissions from process heaters and fugitives, because the processes will be closed systems and most, if not all CO_2 is removed at the Amine Unit. Additionally very little, if any, methane is contained in the NGL that will enter the plant.

The FRAC III Plant will employ a hot oil system that will provide heat to the process. 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. Lone Star NGL plans to utilize the hot oil system as needed to provide heat in the Amine Regeneration unit, the Molecular Sieve 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 FRAC III Plant will have one Hot Oil Heater rated at 215 MMBtu/hr that will support the hot oil system. Additionally, the FRAC III Plant will utilize a Molecular Sieve regeneration heater that will be rated at 59 MMBtu/hr. The combustion of natural gas in these two heaters will result in combustion-related GHG emissions. Both process heaters, will be equipped with Next Generation Ultra-Low NOX burners (NGULNB) and will be further controlled and ducted to individual stacks that will be equipped with Selective Catalytic Reduction (SCR) technology to significantly reduce NOx emissions.

An air-assisted flare will be installed at the Mont Belvieu site to control emergency process releases and streams resulting from maintenance, startup, and shutdown (MSS) activities from FRAC III Plant. No process streams will be routed to the flare during normal operation. Combustion related GHG emissions from the flare will result from the combustion of MSS hydrocarbon streams and fugitive hydrocarbon streams. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 98%.

The FRAC III will utilize a thermal oxidizer (TO) to combust waste gas streams from the process. GHG emissions from the TO will result from waste gas and fuel gas combustion as well as amine unit CO_2 pass through. The waste gas will be converted to CO_2 and water vapor. The thermal oxidizer will have a fuel firing rate of 5 MMBtu/hr and a destruction efficiency (DRE) of 99.9%.

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. Lone Star NGL will implement the TCEQ 28LAER Leak Detection and Repair (LDAR) program for the entire Mont Belvieu site.

The FRAC III Plant will have two emergency diesel generators for use in case of loss of electrical power and an emergency diesel fire water pump in case of fire. These engines are operated in nonemergency situations for up to 36 hours for testing and maintenance to ensure reliability during emergency situations. The combustion of diesel in the emergency engines will result in combustion-related GHG emissions.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

FIN	EPN	Description
3HR15.001	3HR15.001	Hot Oil Heater (Combustion Unit) rated at 215 MMBtu/hr.
3HR15.002	3HR15.002	Molecular Sieve Regeneration Heater (Combustion Unit) rated at 59 MMBtu/hr.
3SK25.002, 3HT16.005	3SK25.002	Thermal Oxidizer (Combustion Unit) for control of waste gas streams.
1SK25.001	1SK25.001	Flare (Combustion Unit) used for control of Maintenance, Startup, and Shutdown (MSS) emissions.
3FUG	3FUG	Fugitive emissions from the FRAC III Plant
3GEN.001	3GEN.001	Emergency Diesel Generator
3GEN.002	3GEN.002	Emergency Diesel Generator
3PM18.004	3PM18.044	Fire Water Pump
3MSS1	3MSS1	Miscellaneous Maintenance

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]		
3HR15.001	3HR15	FRAC III Hot Oil Heater	CO_2	130,045	130,572	7.12 lbs CO_2/bbl. See permit condition III.B.1.b
			CH_4	6.23		
			N_2O	1.25		
3HR15.002	3HR15	FRAC III Regeneration Heater	CO_2	35,687	35,831	1.95 lbs CO_2/bbl. See permit condition III.B.2.b
			CH_4	1.71		
			N_2O	0.34		
1SK25.001	1SK25.001	Flare (waste gas only)	CO_2	397	397	Good combustion practices. See permit condition III.B.4
			CH_4	No Emission Limit Established[4]		
			N_2O	No Emission Limit Established[4]		
3SK25.002, 3HT16.005	3SK25.002	FRAC III Thermal Oxidizer	CO_2	51,341	51,357	Good combustion practices, and annual compliance testing. See permit conditions III.B.3
			CH_4	0.16		
			N_2O	0.04		
3FUG	3FUG	FRAC III Fugitives	CO_2	No Emission Limit Established[5]	No Emission Limit Established[5]	Implementation of LDAR Program. See Permit condition III.B.6
			CH_4	No Emission Limit Established[5]		
3GEN.001	3GEN.001	FRAC III Emergency Diesel Generator 1	CO_2	15	15	Good combustion practices, non-emergency operation limited to 36 hrs/yr.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Emission Limit Established[4]		
3GEN.002	3GEN.002	FRAC III Emergency Diesel Generator 2	CO_2	17	17	Good combustion practices, non-emergency operation limited to 36 hrs/yr.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Emission Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
3MSS1	3MSS1	FRAC III Miscellaneous	CO_2	No Emission Limit Established[6]	No Emission Limit Established[6]	Implementation of good operational practices.
			CH_4	No Emission Limit Established[6]		
3PM18.044	3PM18.04 4	FRAC III Fire water Pump	CO_2	15	15	Good combustion practices, non-emergency operation limited to 36 hrs/yr.
			CH_4	No Emission Limit Established[4]		
			N_2O	No Emission Limit Established[4]		
Totals[7]			**CO_2**	**217,516**	**CO_2e 218,220**	
			CH_4	**8.72**		
			N_2O	**1.63**		

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): CO_2= 1, CH_4 = 25, N_2O = 298
4. All values indicated as “No Emission Limit Established” are less than 0.01 TPY with appropriate rounding. The emission limit will be a design/work practice standard as specified in the permit.
5. Fugitive process emissions from EPN 3FUG are estimated to be 0.61 TPY of CH_4, 0.003 TPY CO_2, and 15 TPY CO_2e. The emission limit will be a design/work practice standard as specified in the permit.
6. FRAC III Miscellaneous emissions from 3MSS1 are estimated to be 0.0002 TPY CO_2, 0.005 TPY CH_4, and 0.12 TPY CO_2e.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions and FRAC III Miscellaneous emissions.

III. Special Permit Conditions

A. **Site-wide Requirement**

The Permittee shall install, operate, and maintain electric driven engines for refrigeration compression.

B. **Emission Unit Work Practice Standards, Operational Requirements, and Monitoring**

1. Hot Oil Heater (EPN: 3HR15.001)

a. FRAC III Plant will be equipped with one hot oil heater rated at 215 million British thermal units per hour (MMBtu/hr) (3HR15.001). The hot oil heater will be ducted to a stack that will be equipped with Selective Catalytic Reduction (SCR) technology.

b. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in short tons/yr using equation C-2a in 40 CFR Part 98 Subpart C. 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), converted to short tons.

d. 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, as published on November 29, 2013 (78 FR 71904) (*2013 Revisions to the Greenhouse Gas Reporting Rule and Final confidentiality Determinations for New or Substantially Revised Data Elements; Final Rule*).

e. Fuel for the heater shall be limited to fuel gas (pipeline-quality natural gas and/or ethane product) 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 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. Permittee shall measure and record the fuel type and fuel flow rate 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 operating hours and maximum firing rate), which will be calibrated on an annual basis.

g. Permittee shall calibrate and perform a preventative maintenance check of the fuel gas flow meters and document annually.
h. The Permittee shall install and operate oxygen analyzers on the combustion chamber to continuously monitor and record oxygen concentration in the hot oil heater. Oxygen reading will be reduced to an averaging period of 6 minutes or less and record it at that frequency.
i. The Permittee shall not allow the excess air in the combustion chamber of the heaters to exceed 15%.
j. 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, with the following exception: a relative accuracy test audit is not required every four quarters (i.e., two successive semiannual CGAs may be conducted).
k. Permittee shall clean the burner tips of each hot oil heater during an annual shutdown if occurring. If a planned outage is not performed, cleaning may be delayed until the next planned outage, not to exceed 5 years from the previous cleaning.
l. Permittee shall install, operate, and maintain an automated air/fuel control system.
m. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
n. Permittee shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
o. The heater will be equipped with low-NO_x staged/quenching (flue gas re-circulating) burners with burner management systems.
p. The heater shall be tuned for thermal efficiency on an annual basis.
q. The heater is 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 and startups will be limited to 30 minutes.
r. On or after the date of initial startup, the Permittee shall not discharge or cause the discharge of emissions from the hot oil heater (3HR15.001) in excess of 7.12lbs CO_2/barrel (bbl - a barrel contains 42 gallons) of NGL processed on a 365-day rolling average. 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.B.1.e. by the measured daily natural gas liquids processed from the FRAC III Plant (bbl) required in Special Condition IV.B.

2. Regeneration Heater (EPN: 3HR15.002)

a. FRAC III Plant will be equipped with one regeneration heater rated at 59.0 MMBtu/hr (3HR15.002). The regeneration heater will be ducted to a stack that will be equipped with Selective Catalytic Reduction (SCR) technology.
b. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in short tons/yr using equation C-2a in 40 CFR Part 98 Subpart C, converted to short tons. Compliance shall be based on 365 days rolling basis.
c. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month 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), converted to short tons.
d. 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, as published on November 29, 2013 (78 FR 71904) (*2013 Revisions to the Greenhouse Gas Reporting Rule and Final confidentiality Determinations for New or Substantially Revised Data Elements; Final Rule*).
e. Fuel for the heater shall be limited to fuel gas (pipeline-quality natural gas and/or ethane product) 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. Permittee shall measure and record the fuel type and fuel flow rate 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 operating hours and maximum firing rate), which will be calibrated on an annual basis.
g. Permittee shall calibrate and perform a preventative maintenance check of the fuel gas flow meters and document annually.
h. Permittee shall install and operate oxygen analyzers on the combustion chamber to continuously monitor and record oxygen concentration in the hot oil heater. Oxygen reading will be reduced to an averaging period of 6 minutes or less and record it at that frequency.
i. The permittee shall not allow the excess air in the combustion chamber of the heaters to exceed 15%.

j. 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, with the following exception: a relative accuracy test audit is not required every four quarters (i.e., two successive semiannual CGAs may be conducted).
k. Permittee shall clean the burner tips of each hot oil heater during an annual shutdown if occurring. If a planned outage is not performed, cleaning may be delayed until the next planned outage, not to exceed 5 years from the previous cleaning.
l. Permittee shall install, operate, and maintain an automated air/fuel control system.
m. Permittee shall calibrate and perform preventative maintenance on the air/fuel control analyzers once per quarter, at a minimum.
n. Permittee shall utilize insulation materials (e.g. ceramic fiber blankets and Kaolite™) where feasible to reduce heat loss.
o. The heater will be equipped with low-NO_x staged/quenching (flue gas re-circulating) burners with burner management systems.
p. The heater shall be tuned for thermal efficiency on an annual basis.
q. The heater is 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 and startups will be limited to 30 minutes.
r. On or after the date of initial startup, the Permittee shall not discharge or cause the discharge of emissions from the regeneration heater (3HR15.002) in excess of 1.95 lbs CO_2/barrel (bbl - a barrel contains 42 gallons) of NGL processed on a 365-day rolling average. 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.B.2.b. by the measured daily natural gas liquids processed from the FRAC III Plant (bbl) required in Special Condition IV.B.

3. Thermal Oxidizer Emission Source (EPN:3SK25.002)

a. FRAC III Plant is equipped with a thermal oxidizer (3SK25.002). GHG emissions from the thermal oxidizers result from fuel gas combustion (pipeline-quality natural gas and/or ethane product) and waste gas combustion (waste gas from the amine unit).
b. The thermal oxidizer is designed to combust low-VOC concentration waste gas from the amine units and has a fuel rating of 5 MMBtu/hr when firing natural gas.
c. The flow rate of the waste gas combusted shall be measured and recorded using an operational non resettable elapsed flow meter at the thermal oxidizer.

d. Waste gas will be sampled and analyzed on a quarterly basis for composition. The sampled data will be used to calculate GHG emissions to show compliance with the limits specified in Table 1.
e. The thermal oxidizer shall have an initial stack test, and annual compliance testing, to verify destruction and removal efficiency (DRE) of at least 99.9 % for VOC.
f. For burner combustion, natural gas and/or ethane product fuel usage (scf) is recorded using an operational non-resettable elapsed flow meter at the thermal oxidizer.
g. Permittee shall calculate CO_2 emissions, on a monthly basis, using equation W-3 consistent with 40 CFR Part 98, Subpart W [98.233(d)(2)].
h. Periodic maintenance will help maintain the efficiency of the thermal oxidizer and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications.
i. The Permittee shall maintain the combustion temperature at a minimum of 1,400 ºF at all times when processing waste gases from the amine unit in the thermal oxidizer. Temperature monitoring of the thermal oxidizer will ensure proper operation. The Permittee shall install and maintain a temperature recording device with an accuracy of the greater of ±0.75 percent of the temperature being measured expressed in degrees Celsius or ±2.5ºC.
j. The thermal oxidizer's exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizers. The temperature measurement devices shall reduce the temperature readings to an averaging period of 6 minutes or less and record it at that frequency. Monitor downtime will not exceed 5% of the annual operating hours of the thermal oxidizer.
k. Premittee does not plan to use oxygen analyzers on the waste gas streams to the thermal oxidizers. will obtain, at least once per year, an updated analysis of the Amine Unit waste gas streams, to document the CO_2 and methane content of the streams. This analysis will be considered to be representative of the gas streams for the calendar year during which it was taken, and will be used to estimate emissions from the thermal oxidizer (together with fuel gas combustion).

4. Flare Emission Sources (EPN: 1SK25.001)

a. Emergency process releases and streams resulting from MSS activities from FRAC III Plant shall be vented to an existing flare (1SK25.001).
b. The flare is air assisted.
c. The flare shall have a minimum destruction and removal efficiency (DRE) of 98% based on flow rate and gas composition measurements as specified in 40 CFR § 98.233(n).

d. The flare (1SK25.001) is an intermittent use MSS flare, not a continuous process flare.
e. Permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and duration of each MSS event. 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. These records must be kept for five years following the date of each event.
f. 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.

5. Emergency Generator Engine (EPN: 3GEN.001 and 3GEN.002) Emergency and Firewater Pump Engine (EPN: 3PM18.004)

a. FRAC III Plant will have two emergency diesel generators (3GEN.001 and 3GEN.002) for use in the case of loss of electrical power and an emergency diesel fire water pump (3PM18.044) for use in case of fire.
b. The engines shall be diesel fired. Fuel used in the engines will meet the requirements of 40 CFR 80.510(b) regarding sulfur content (15 ppmw maximum) and a minimum Cetane Index of 40 or maximum aromatic content of 35% by volume.
c. The Permittee shall install a non-resettable hour meter prior to start-up of each engine.
d. The two emergency generator engines purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(b).
e. The emergency firewater pump engine purchased will be certified to meet the applicable emission standards of 40 CFR 60.4205(c).
f. The engines may be operated for the purpose of maintenance checks and readiness testing for up to 36 hours per year per engine to ensure reliability during emergency situations.
g. The emission limit in Table 1 is based on each emergency generator engine operating 36 hours a year for maintenance and testing.
h. Compliance with the Annual Emission Limit shall be demonstrated on a 12-month total, rolling monthly, calculated in accordance with 40 CFR §98.33(a)(1)(i) and §98.33(c)(1).

6. Fugitive Emission Sources (EPN: 3FUG)

1. Fugitive Emission Sources Work Practice and Operational Requirement

a. The Permittee shall implement the TCEQ 28 LAER Leak Detection and Repair (LDAR) program on the VOC and fuel gas (high methane content) streams at the FRAC III Plant to minimize emissions from piping fugitive leaks.

b. The Permittee shall use low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers which do not emit GHGs.

2. Emission from MSS Activities (EPN: 3MSS1)

a. MSS activities shall be minimized through implementation of good operational practices.

b. During Plant start up, the off-specification products will be injected and stored underground (with no emissions to the atmosphere) and returned to the process once the plant reaches normal operation.

c. During Plant shut down, the blow down emissions will be routed to the flare.

d. Certain maintenance activities (i.e. replacement of analyzer filters/screens, filter/meter maintenance/replacement (fuel gas meter proving), and spare pump start up) will result in emissions to atmosphere.

e. Permittee shall maintain records of each MSS activity to include date, time, and duration of each MSS event

f. For MSS emissions that are released to atmosphere, the Permittee shall also include a record of hydrocarbon concentration as measured by the LEL meter or Organic Vapor Analyzer with the records required in III.B.6. 2.e.

C. **Continuous Emissions Monitoring Systems (CEMS)**

1. As an alternative to Special Conditions III.B.1.h and III.B.2.h, 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 uses 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, the permittee will monitor the following parameters and summarize the data on a calendar month basis.

   a. Operating hours for all air emission sources;
   b. The natural gas fuel and or ethane product 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 and/or ethane product, quarterly fuel sampling of waste gas; and
   d. The daily natural gas liquids processing rate for the FRAC III Plant.

B. Permittee shall maintain the daily production volumes of natural gas liquids produced for the FRAC III Plant in barrels per day (bbl/day). Records shall be maintained for a period of five years.

C. Permitee 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 waste gas from the amine unit. This analysis 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 unit 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 Maximum Allowable Emission Rates Table (MAERT).

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

G. Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of the facility, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device at the facility; the occurrence and duration of any startup, shutdown, or malfunction, annual tuning of heaters; all records relating to performance tests and monitoring of combustion equipment; calibrations, checks, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements; 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.

H. 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.

I. Excess emissions shall be defined as any period in which the facility emission exceeds a maximum emission limit set forth in this permit.
J. 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.
K. 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 holder of this permit shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units 3HR15.001 (Hot Oil Heater), 3HR15.002 (Regeneration Heater), 3SK25.002, 3HT16.005 (Thermal Oxidizer) and to determine the initial compliance with the CO_2 emission limits established in this permit.
B. 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.
    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 exceedance 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.

C. For the Thermal Oxidizer, calculate the CO_2 hourly average emission rate determined under maximum operating test conditions, then convert to lb/scf of acid gas flow. Use the following equation to calculate the annual emissions.

$$CO_2\,TPY = 107{,}815\,\frac{scf}{hr} \times 8{,}760\,\frac{hr}{year} \times lb\,\frac{CO_2}{scf} \div 2{,}000\,\frac{lb}{ton}$$

Where:

107,815 scf/hr = the waste gas plus pilot gas flow rate to the thermal oxidizers

1. If the above calculated CO_2 emission totals do not exceed the tons per year (TPY) limits specified on Table 1, no compliance strategy needs to be developed.
2. If any of the above calculated CO_2 emission totals exceed the tons per year (TPY) limits specified in Table 1, the facility shall;
   a. Document the predicted exceedance 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.

D. 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) must be conducted and a written report of the performance testing results furnished to the EPA. Additional sampling may be required by TCEQ or EPA.

E. 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.

F. Performance testing must be conducted using a representative rate of operation.

G. Fuel sampling for emission units 3SK25.002, 3HT16.005 (Thermal Oxidizer), and 1SK25.001 (Flare) shall be conducted in accordance with 40 CFR Part 98.

H. Flare compliance determination shall be made following the requirements in 40 CFR Part 60 sections 60.18(f)(1) through 60.18 (f)(4).

I. The Permittee shall perform initial performance demonstration testing of the thermal oxidizer at the site. The thermal oxidizer shall operate at the maximum production rate during stack emissions testing. The Permittee shall measure CH_4 concentrations in the thermal oxidizer inlet and exhaust streams to demonstrate a minimum destruction efficiency of 99.9% by weight at a minimum combustion chamber temperature of 1,400 °F.

J. The Permittee shall record the combustion chamber temperature and combustion chamber set-point temperature during the performance test. These and any additional operational parameters shall be identified in the test protocol and recorded during testing. Following the performance test, the thermal oxidizer shall be operated at or above the combustion chamber set-point temperature used to demonstrate compliance, and at all times greater than 1,400 °F.

K. For the thermal oxidizer the sampling site and velocity traverse point shall be selected in accordance with EPA Test Method 1or 1A. The gas volumetric flow rate shall be measured in accordance with EPA Test Method 2, 2A, 2C, 2D, 2F, 2G, or 19. The dry molecular weight shall be determined in accordance with EPA Test Method 3, 3A or 3B. The stack gas moisture shall be determined in accordance with EPA Test Method 4. These methods must be performed, as applicable, during each test run.

L. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The owner or operator must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.

M. The owner or operator must 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 facility must provide at least 7 days prior notice of the rescheduled date of the performance test.

N. The owner or operator 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.

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

P. 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 (6EN-AA)
EPA Region 6
1445 Ross Avenue
Dallas, TX 75202