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-106793-GHG

PERMITTEE: Targa Gas Processing LLP
1000 Louisiana St., Suite 4300
Houston, TX 77002

FACILITY NAME: Longhorn Gas Plant

FACILITY LOCATION: NE on FM51 from US-380
turn L after 5.4 mi drive 1.25 mi to plant
Wise County, TX 76234

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 Targa Gas Processing LLC - Longhorn Gas Plant for Greenhouse Gas (GHG) emissions. The Permit authorizes the construction of a natural gas processing plant near Decatur in Wise County, Texas.

Targa is authorized to construct the natural gas 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) permit No. 106793. 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 Targa 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
Wren Stenger, Director
Multimedia Planning and Permitting Division

6/17/2013
Date

Targa Gas Processing LLC
Longhorn Gas Plant (PSD-TX-106793-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Draft Permit Conditions

PROJECT DESCRIPTION

The 200 MMSCFD Longhorn Gas Plant (LGP) will be designed and constructed for deep ethane recovery via inlet separation, amine treatment, glycol dehydration, and cryogenic processing. Natural gas will flow into the plant from either of two delivery points through high pressure pipelines equipped with onsite pipeline pig receivers (EPN 7-MSS, EPN 8-MSS). Gas from the pig receivers flows into the inlet slug catcher for liquid removal. The gas is then measured and goes through the Plant Inlet Separator for removal of any additional water, solids or liquids. The natural gas then flows to the Plant Inlet Filter/Separator for filtering of smaller particles of water and solids. Condensate from all inlet separation equipment is pumped back into a pipeline for delivery and handling at an existing facility located offsite.

After inlet separation and filtration, the inlet gas flows into the Amine Contactor, where the gas is contacted with an aqueous solution of UCARSOL AP-814 amine to remove CO_2. CO_2 exits with the amine from the bottom of the contactor and is heated and regenerated using closed hot oil system in the Amine Regenerator. Hot oil is circulated and supplied by the Heating Medium Heater (EPN 4). The CO_2 released from the regeneration process is routed to the onsite Regenerative Thermal Oxidizer (RTO, EPN 5), where the vent gas is combusted and burned. When the RTO is down for maintenance the vent gas is routed to a flare (EPN 15). Treated gas (less CO_2) exits the Amine Contactor and is routed to the Treated Gas Coolers where it is cooled with ambient air. Any condensed water drops out in the Treated Gas Scrubber. Water that does not drop out is recycled back to the amine process for reuse.

Gas from the Treated Gas Scrubber then goes to the TEG Contactor where water removal is accomplished by contacting with Triethylene Glycol (TEG). The TEG is then regenerated in a 2.0 MMBtu/hr direct fired reboiler (EPN 1). Flash vapors from this unit go through an exchanger to remove condensables and then are routed back to the reboiler burner as fuel. Water removed from the TEG in the reboiler is cooled and any residual vapors are routed to the RTO (EPN 5) for combustion. During RTO maintenance the residual vapors are vented to the flare (EPN 15). Dehydrated gas leaves the contactor and is exchanged with incoming glycol in a side mounted exchanger and then routed to the Mole Sieve Inlet Separator to recover any glycol carryover. Any recovered glycol/water is recycled back to the TEG system for reuse.

Gas exits the Mole Sieve Inlet Separator and flows into the Inlet Filter / Separator where it is again filtered prior to entering the Mole Sieve Dehydrator Beds. The gas flows into two (2) of the three (3) Mole Sieve Dehydrators for removal of any traces of water prior to the cryogenic process. Each dehydrator contains molecular sieve dehydration beads that absorb trace amounts of water from the gas stream. Two vessels will be used to dehydrate inlet gas while the third vessel is being regenerated. Dehydrated high pressure gas is used for regeneration. The regeneration gas is compressed by a Sundyne Compressor. The compressed gas flows to the Regeneration Gas Heater (EPN 3). The heater duty is not a 24-hour, continuous duty operation but only needed a few hours per day per bed. The hot gas flows from the heater to the dehydrator vessel being regenerated. The water is removed from the molecular sieve by evaporation. The hot gas and vaporized water flow to the Regeneration Gas Cooler, where the gas is cooled and the water is condensed. The cool regeneration gas stream flows to the Regeneration Gas Scrubber where condensed water is level controlled to the closed drain system flash tank and then to the plant waste water tank. The cooled gas recycles to the inlet of the plant upstream of the Inlet Filter/Separator. Dehydrated gas from the mole sieve beds flows into the Mole Sieve Dust Filters to remove any mole sieve particles prior to entry into the cryogenic process.

Gas flow into the Cryogenic Process is split to two (2) plate fin type exchangers. Normally 60% will go to the Inlet Gas Exchanger, while the remainder flows to the Gas/Product Exchanger, then the Demethanizer reboiler, and then to the Demethanizer Side Reboiler or Heater. The exchangers are combined into one plate fin exchanger. Gas vapor and liquid from the exchangers are combined and enter the Demethanizer Tower. The inlet gas is further cooled by heat exchange with propane refrigerant in the Inlet Gas Chiller. There are three (3) 1500-horsepower (hp) electric driven screw compressors that supply the process with refrigerant propane for cooling of the gas. Any heavier components collected in the refrigeration compressor scrubbers or system goes to the closed drain system flash tank. Refrigerant propane is loaded by truck into the Refrigerant Accumulator. Vapor and liquids from the chiller then flow to the Cold Separator. The Cold Separator is used to separate vapor and liquid hydrocarbons that have condensed as a result of chilling in the exchangers. Most of the vapor exiting the Cold Separator flows into the Expander side of the Expander/Booster Compressor where the temperature and pressure are reduced and enter the Demethanizer Tower. A portion of the Cold Separator liquids combines with a portion of the Cold Separator overhead vapors and flows to the Demethanizer Feed Subcooler where it is cooled with cold residue gas. The pressure is reduced and the stream feeds the top of the Demethanizer Tower. The remainder of the Cold Separator Liquid is level controlled to reduce the pressure and enters the Demethanizer Tower.

The Demethanizer Tower is a packed tower with a bottoms reboiler and a side reboiler (also known as a side heater). Liquids leaving the bottom of the tower flow to the Product Surge Tank. The product is then pumped by the Product Booster Pumps which are tandem seal centrifugal pumps, through the Gas/Product Exchanger where the product is heated by exchange with the inlet gas and then to the Product Pipeline Pumps which are tandem seal multistage centrifugal pumps. Overhead gas vapors (residue) from the Demethanizer Tower flows to the Demethanizer Feed Subcooler, then to the Inlet Gas Exchanger where the temperature is increased by heat exchange with the inlet gas. The residue leaving this exchanger is compressed by the Booster Compressor side of the Expander/Booster Compressor. Boosted residue is cooled in the Booster Compressor After-cooler and then flows to the residue compressors. Residue compressors comprise three (3) 5,000 hp electric motor-driven reciprocating compressors which take the residue gas from plant residue pressure to pipeline sales pressure. Any compressor liquids accumulated from scrubbers is routed to the closed drain system flash tank. After cooling with fin fan units the residue gas is delivered by pipeline to the sales point offsite.

The closed drain system is designed with a flash tank that will operate at 40 psig and will route all flash vapors to a vapor recovery unit (VRU). Two VRUs will be installed at the site so that when one is down or undergoing maintenance, the other unit will compensate. Liquids from the flash tank go to the low pressure condensate tanks (EPNs 17, 18). Water is separated out from the condensate and is drained to the waste water tank (EPN 16). Condensate is loaded out via trucks (FUG-2). Emissions from truck loading (FUG-2) do not result in any GHG emissions. Flash, working, and breathing vapors from the low pressure condensate tanks are controlled by the vapor recovery units (VRU) and delivered to the plant fuel system. The facility is equipped with an open (atmospheric) drain system to collect rain water and skid drain liquids to the open drain sump (EPN 21). The water collected in the sump flows to the waste water tank (EPN 16). Water in the waste water tank is loaded onto trucks for offsite handling. Targa estimates no emissions will result from the waste water tank (EPN 16), low pressure condensate tanks (EPNs 17 and 18), nor the open drain sump (EPN 21).

Two 40 CFR §60.18 compliant flares (EPNs 6 and 15) will be located on the facility site. Flare-1 (EPN 6) is air assisted. Flare-2 (EPN 15) is unassisted. Both flares are designed for smokeless operation. All pressure safety valves (PSV) containing heavier than air hydrocarbons, refrigeration system PSV's and compressor blowdowns and residue compressor blowdown vapors are routed to the EPN 6 flare. Emissions resulting from the amine unit and TEG dehydrator during RTO downtime will also be routed to the EPN 15 flare.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

EPN	Description
1	TEG-1 Glycol Reboiler rated at 2.0 MMBtu/hr.
3	One Molecular Sieve Regeneration Heater rated at 12 MMBtu/hr.
4	One Hot Oil Heater rated at 98 MMBtu/hr.
5	One Regenerative Thermal Oxidizer for control of waste gas streams.
5-MSS	Emissions from RTO startup.
6	Flare-1 pilot.
6-MSS	Flare used for control of Maintenance, Startup, and Shutdown (MSS) emissions.
7-MSS	16" Pipeline pig receiver (PR-1).
8-MSS	12" Pipeline pig receiver (PR-2).
15	Flare-2 pilot.
15-MSS	Flare used for control of process vents from the Amine Unit and TEG Dehydrator during RTO downtime.
FUG-1	Fugitive emissions from plant-wide fugitive components.

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 12-month rolling average basis 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]		
1	1	TEG-1 Glycol Reboiler	CO_2	1,024	1,024	1,783.23 CO_2 lb/MMSCF (combined limit for the three units) on 365- day rolling. See permit condition III.B.2.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[4]		
3	3	HTR-1 Mol. Sieve Regen Heater	CO_2	6,349	6,355	
			CH_4	0.13		
			N_2O	0.01		
4	4	HTR-2 Hot Oil Heater	CO_2	50,174	50,222	
			CH_4	0.94		
			N_2O	0.09		
2,15	5	RTO-1 Regen Thermal Oxidizer	CO_2	167,739	167,897	Good combustion practices and annual compliance testing. See permit condition III.A.1.
			CH_4	1.48		
			N_2O	0.41		
5-MSS	5-MSS	RTO-1 Startup	CO_2	1.40	1.40	
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
6	6	Flare 1	CO_2	269	269	Good combustion practices and annual compliance testing. See permit condition III.C.1
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
6	6-MSS	Flare 1 MSS	CO_2	10	10	
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
7-MSS	7-MSS	PR-1 16" Receiver	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	No more than 24 events per year.
			CH_4	No Numerical Limit Established[5]		
8-MSS	8-MSS	PR-2 12" Receiver	CO_2	No Numerical Limit Established[5]	No Numerical Limit Established[5]	No more than 24 events per year.
			CH_4	No Numerical Limit Established[5]		
15	15	Flare 2	CO_2	80	80	Good combustion practices and annual compliance testing. See permit condition III.C.2
			CH_4	No Numerical Limit Established[4]	No Numerical Limit Established[4]	
			N_2O	No Numerical Limit Established[4]	No Numerical Limit Established[4]	
15	15-MSS	Flare 2 during RTO downtime	CO_2	2,910	2,911	
			CH_4	0.03		
			N_2O	No Numerical Limit Established[4]		
FUG-1	FUG-1	Plant-wide Fugitive Components	CO_2	No Numerical Limit Established[6]	No Numerical Limit Established[6]	Implementation of LDAR Program. See permit condition III.E.1.
			CH_4	No Numerical Limit Established[6]		
Totals[7]			**CO_2**	**228,558**	**229,173**	
			CH_4	**21.78**		
			N_2O	**0.51**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average basis.
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. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding.
5. Pipeline pigging emissions (7-MSS and 8-MSS) are estimated to be 0.18 TPY of CH_4 and 3.8 TPY CO_2e.
6. Fugitive process emissions (FUG-1) are estimated to be 1.5 TYP of CO_2, 19 TPY of CH_4, and 401 TPY CO_2e.

In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.

7. 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. Thermal Oxidizer Emission Source (EPN 5 and EPN 5-MSS)

1. Thermal Oxidizer Work Practice and Operational Requirements

a. The facility is equipped with a regenerative thermal oxidizer (RTO-1). GHG emissions from the thermal oxidizer result from fuel gas combustion (pipeline quality natural gas) and waste gas combustion (waste gas from amine and dehydration processes).
b. The RTO is designed to combust low-VOC concentration waste gas from the amine unit and the TEG dehydration unit, and can self-sustain the normal operating temperature with waste gas heat input as low as 8-10 Btu/scf.
c. The RTO shall have an initial stack test, and annual compliance testing, to verify hydrocarbon destruction and removal efficiency (DRE) of at least 99%.
d. The facility is equipped with an amine unit. The waste gas from the amine regenerator is routed to the RTO for combustion.
e. The facility is equipped with a TEG dehydration unit. The waste gas from the dehydration unit is routed to the RTO for combustion.
f. For burner combustion, natural gas fuel usage during start up (scf) will be recorded using an operational non-resettable elapsed flow meter at the RTO.
g. The flow rate of the waste gas combusted shall be measured and recorded using an operational non-resettable elapsed flow meter at the RTO.
h. 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.
i. 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)].
j. Periodic maintenance will help maintain the efficiency of the RTO and shall be performed at a minimum annually or more often as recommended by the manufacturer specifications.
k. The Permittee shall maintain the combustion temperature at a minimum of 1,500 °F at all times when processing waste gases from the amine unit and TEG dehydration unit in regenerative 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 ±2.5°C.
l. The RTO's exhaust temperature shall be continuously monitored and recorded when waste gas is directed to the oxidizer. The temperature measurement device

shall reduce the temperature readings to an averaging period of 15 minutes and record it at that frequency.

m. Oxygen analyzers shall continuously monitor and record oxygen concentration when waste gas is directed to the RTO. It shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.
n. The oxygen analyzers shall be quality-assured at least semiannually 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 once every four quarters (i.e., two successive semiannual CGAs may be conducted).

B. Requirements for Heaters (EPN 1, EPN 3, and EPN 4)

1. Heater Work Practice and Operational Requirements

a. The plant has one hot oil heater (EPN 4) rated at 98 million British thermal units per hour (MMBtu/hr). The dehydration process has a TEG reboiler that uses heat provided by direct fire from a natural gas-fired heater rated at 2 MMBtu/hr (EPN 1). The molecular sieve also has a regeneration heater rated at 12 MMBtu/hr (EPN 3).
b. Permittee shall calculate, on a 365-day rolling basis, the amount of CO_2 emitted from EPN 1, 3 and 4 in tons/yr using equation C-2a in 40 CFR Part 98, Subpart C, converted to short tons. For equation C-2a, the mass or volume of fuel combusted shall be measured on a daily basis and calculations shall be based on the daily measurement. Records shall be kept for a period of five years of the daily fuel combusted. Compliance shall be based on a 365-day rolling total.
c. Permittee shall calculate, on 365-day rolling basis the CH_4 and N_2O emissions in tons/yr. 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). For equation C-9a, the amount of fuel combusted shall be based on a daily measured amount of fuel combusted. The resulting amount of CH_4 and N_2O calculated shall be converted to short tons.
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, as published on October 30, 2009 (74 FR 56395).
e. 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. 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 the inlet. The flow meter must be calibrated on an annual basis.
g. An oxygen analyzer shall continuously monitor and record oxygen concentration in the hot oil heater (EPN 4). It shall reduce the oxygen readings to an averaging period of 6 minutes or less and record it at that frequency.
h. The oxygen analyzer 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 once every four quarters (i.e., two successive semiannual CGAs may be conducted).
i. The Permittee shall not allow the excess air in the combustion chamber of the heaters to exceed 15%.
j. The hot oil heater (EPN 4) will be equipped with low-NO_x staged/quenching (flue gas recirculating) burners with burner management systems.
k. The heaters shall be tuned for thermal efficiency on an annual basis.
l. 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 and startups will be limited to 30 minutes.

2. Heater BACT Emission Limit

On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the plant (EPN 1, EPN 3, and EPN 4) in excess of 1783.23 lbs CO_2/MMscf on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the amount of CO_2 as required in Special Condition B.1.b and sum the resultant amount for EPN 1, 3 and 4. The summed resultant amount of TPY CO_2 is divided by the measured daily natural gas processed from the plant (MMSCFD) and converted to lb CO_2/MMscf.

C. Flare Emission Sources

1. Flare-1 Work Practice and Operational Requirements (EPN 6 and EPN 6-MSS)

a. MSS emissions from the facility shall be vented to Flare-1 (EPN 6, EPN 6-MSS).
b. The flare shall have a minimum destruction and removal efficiency (DRE) of 99% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).
c. The flare (EPN 6, EPN 6-MSS) is an intermittent use flare, not continuous process flare. The flare shall only combust pilot gas as a continuous stream.
d. The flare is air assisted.
e. The Permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and duration of each MSS event, which shall not exceed nine (9) events each per year for blowdowns of the residue and refrigerant compressors, and fifty-two (52)

one-hour pigging events per year. 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 flowrate) 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.

2. **Flare-2 Work Practice and Operational Requirements (EPN 15 and EPN 15-MSS)**

a. Emissions from the amine unit and TEG dehydration unit during RTO maintenance shall be vented to Flare-2 during RTO downtime (EPN 15, EPN 15-MSS).

b. The flare shall have a minimum destruction and removal efficiency (DRE) of 99% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).

c. The flare (EPN 15, EPN 15-MSS) is an intermittent use flare, not continuous process flares. The flare shall only combust pilot gas as a continuous stream.

d. The flare is unassisted.

e. The Permittee must record the time, date, fuel heat input (HHV) in MMBtu/hr and duration of each MSS event, which shall not exceed a total of 124 hours per year. 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 flowrate) 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.

D. Pipeline Pig Receivers (EPN 7-MSS and EPN 8-MSS)

1. The Permittee must record the time and date of each pigging event, which shall not exceed a total of 24 events per year. These records must be kept for five years following the date of each event.

E. Fugitive Emission Sources (EPN FUG-1)

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

a. The Permittee shall use dry compressor seals instead of wet seals to reduce leaks.

b. The Permittee shall use rod packing for reciprocating compressors and will conduct annual inspections of the packing materials.

c. The Permittee shall use low-bleed gas-driven pneumatic controllers which emit less gas or compressed air-driven pneumatic controllers which do not emit GHGs.
d. The Permittee shall implement the TCEQ 28VHP Leak Detection and Repair (LDAR) program for fugitive emissions of methane.

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 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. Semi-annual fuel sampling for natural gas, quarterly fuel sampling of waste gas; and
d. The daily natural gas processing rate for the facility.

B. Permittee shall maintain the daily production volumes of natural gas liquids produced for the Longhorn Gas Plant in barrels per day (bbl/day). Records shall be maintained for a period of five years.
C. Permittee will implement the TCEQ 28VHP 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 facility emission limits for comparison to the facility emissions found in Table 1, except a 365-day rolling average is required for the BACT-emission limit for EPN 1, EPN 3, and EPN 4.
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 30^{th} 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 Permittee shall perform an initial stack test to establish the actual quantities of air contaminants being emitted into the atmosphere from emission units EPN 1, EPN 3, EPN 4, and EPN 5 and 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.
    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.

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) 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.

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 must be conducted using a representative rate of operation.
E. Fuel sampling for emission units EPN5, EPN 6, and EPN 15 shall be conducted in accordance with 40 CFR Part 98.
F. 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 regenerative thermal oxidizer inlet and exhaust streams to demonstrate a minimum destruction efficiency of 99% by weight at a minimum combustion chamber temperature of 1,500 °F.
G. 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 RTO shall be operated at or above the combustion chamber set-point temperature used to demonstrate compliance, and at all times greater than 1,500 °F.
H. For the RTO 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.
I. Performance tests must be conducted under such conditions to ensure representative performance of the affected facility. The Permittee must make available to the EPA such records as may be necessary to determine the conditions of the performance tests.
J. The Permittee 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.
K. 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.

L. 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.

M. 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:

Multi Media Planning and Permitting Division
EPA Region 6
1445 Ross Avenue (6PD-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