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-1264-GHG
PERMITTEE:	Energy Transfer Company 800 E. Sonterra Blvd., Suite 400 San Antonio, TX 78258
FACILITY NAME:	Energy Transfer Company Jackson County Gas Plant
FACILITY LOCATION:	Galow Road 1.25 miles west of FM710 Ganado, TX 77962

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 the Energy Transfer Company (ETC) for Greenhouse Gas (GHG) emissions. The Permit authorizes the construction of four new natural gas processing plants and associated compression equipment at the existing Jackson County Gas Plant located in Ganado, Texas.

ETC is authorized to construct the four natural gas processing plants 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) PSD permit No. PSD-TX-1264. 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 ETC 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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Carl E. Edlund, Director
Multimedia Planning and Permitting Division

Date

ETC, Jackson County Gas Plant (PSD-TX-1264-GHG)
Prevention of Significant Deterioration Permit
For Greenhouse Gas Emissions
Final Permit Conditions

PROJECT DESCRIPTION

Following the construction authorized by this permit, the facility will consist of a liquids handling facility, four natural gas processing plants and their associated compression equipment at the Jackson County Gas Plant in Jackson County, Texas. With this pre-construction permit, ETC will add four natural gas processing plants and their associated compression equipment to the existing liquids handling facility. After the project is operational, the residue gas from the existing liquids handling facility will be directed to the inlet of the four gas processing plants.

The Site location currently includes a Liquids Handling Facility, which is not being modified as part of the project. The liquids handling facility is currently authorized by 30 Texas Administrative Code (TAC) §106.352.

Natural gas from the pipeline passes through horizontal separators, or slug catchers, which separate entrained liquids from the inlet gas. In addition, condensate can be received via pressurized trucks or through "pigging" operations. The liquids retrieved by the "pig" are routed into the slug catcher. After the project is operational, the residue gas will be sent to the four Plants for processing. The vapor pressure of the separated condensate is reduced by the stabilization process (application of heat provided by the Stabilization Unit Heater), where the lighter components are removed and combined with the residue gas for shipping off-site via pipeline (i.e., and transfer to the four plants after the Project). Light-end liquid components driven off in the stabilization process (natural gas liquids, or NGL) will be routed to the four gas processing plants to be constructed under this project. The NGL amine contactors at the four plants will be utilized for the removal of CO_2 and H_2S in order to provide a cleaner product. The CO_2 and H_2S removed are captured and sent to a thermal oxidizer. Each processing plant will consist of an amine unit, a TEG dehydrator unit, thermal oxidizer, two inlet compressors, three refrigeration compressors, and three residue compression engines associated with the process. The project to construct the four gas processing plants will also include a flare for control of maintenance, startup, and shutdown (MSS) emissions from the compressor engines. Processed gas will be sent to pipeline.

The trucks bringing pressurized condensate to the Plants from the field unload into pressure vessels at the site. This process is part of the existing liquids handling facility and is permitted by rule under 30 TAC 106.352. The condensate unloading and NGL loading operations are performed under pressure, in order to prevent emissions to the atmosphere. Therefore, the only emissions associated with these unloading/loading activities are from residual material in the connectors.

The stabilized condensate is stored in pressure vessels and then shipped off-site via truck loading. The stabilized condensate loading facilities used during truck loading are equipped with an electric vapor recovery unit (VRU) system. Emissions captured by the VRU are routed to the Truck Loading Flare for 98% destruction of VOC. When the VRU is down for maintenance, Truck Loading does not occur.

EQUIPMENT LIST

The following devices are subject to this GHG PSD permit.

Emission Unit Id. No.	Description
C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, and C-4100B	Two dual-drive inlet gas compressors rated at 1,775 HP at each of the four plants.
C-1121A, C-1121B, C-1121C, C-2121A, C-2121B, C-2121C, C-3121A, C-3121B, C-3121C, C-4121A, C-4121B, and C-4121C	Three Residue Compressor engines rated at 4,735 HP at each of the four plants.
H-1706, H-2706, H-3706, and H-4706	One Hot Oil Heater rated at 48.5 MMBtu/hr at each of the four plants.
H-7810, H-7811, H-7812, and H-7813	One Trim Heater rated 17.4 MMBtu/hr at each of the four plants.
H-7820, H-7821, H-7822, and H-7823	One Molecular Sieve Regeneration Heater rated at 9.7 MMBtu/hr at each of the four plants.
H-7410, H-7411, H-7412, and H-7413	One Triethylene Glycol (TEG) Dehydration Regeneration Heater rated 3 MMBtu/hr at each of the four plants.
TO-1, TO-2, TO-3, and TO-4	One Thermal Oxidizer at each of the four plants.
P1-FUG, P2-FUG, P3-FUG, and P4-FUG	Fugitive emissions from each of the four plants.
FS-800	Flare used for control of compressor engine blowdown and starter vent emissions.
STAB-FUG	Stabilizer Unit Fugitives
H-741	Stabilizer Unit Heater
TL-Flare	Truck Loading Flare (Controlled Condensate Loading)

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 two working days 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. In addition, Permittee shall notify EPA in writing within 15 days of any such failure described under Section III. This notification shall include 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 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, the TCEQ PSD Permit No. PSD-TX-1264, as finalized 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
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
ETC	Energy Transfer Company
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
MSS	Maintenance, Start-up and Shutdown
NGL	Natural Gas Liquids
N_2O	Nitrous Oxides
NSPS	New Source Performance Standards
OC	Oxidation Catalyst
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
TEG	Triethylene Glycol
TPY	Tons per Year
VRU	Vapor Recovery Unit
USC	United States Code

II. SPECIAL PERMIT CONDITIONS

A. Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 12-month, rolling average, shall not exceed the following:

Table 1. Facility Emission Limits

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, and C-4100B	8 Dual-Drive Inlet Compressor Engines[3]	CO_2	1,723.58	21,944.53	21,966
		CH_4	0.03	0.41	
		N_2O	0.003	0.04	
C-1121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-1121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-1121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 1 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-2121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-2121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.033	
C-2121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 2 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-3121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-3121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	

ID No.	Description	GHG Mass Basis			CO$_2$e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
C-3121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 3 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121A	Unit 1 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121B	Unit 2 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
C-4121C	Unit 3 of 3 Natural Gas Fired Caterpillar 3616 engines Plant 4 of 4	CO_2		18,195.38	18,213
		CH_4		0.34	
		N_2O		0.03	
H-1706	Plant 1 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7810	Plant 1 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-2706	Plant 2 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7811	Plant 2 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-3706	Plant 3 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7812	Plant 3 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	
H-4706	Plant 4 of 4 Hot Oil Heater	CO_2		24,830.49	24,855
		CH_4		0.47	
		N_2O		0.05	
H-7813	Plant 4 of 4 Trim Heater	CO_2		8,908.26	8,917
		CH_4		0.17	
		N_2O		0.02	

ID No.	Description	GHG Mass Basis			CO_2e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
H-7820	Plant 1 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7821	Plant 2 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7822	Plant 3 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7823	Plant 4 Molecular Sieve Regeneration Heater	CO_2		4,966.10	4,971
		CH_4		0.09	
		N_2O		0.01	
H-7410	Plant 1 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7411	Plant 2 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7412	Plant 3 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
H-7413	Plant 4 of 4 TEG Dehydrator Unit Regeneration Gas Heater	CO_2		1,535.91	1,537
		CH_4		0.03	
		N_2O		0.003	
TO-1	Plant 1 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-2	Plant 2 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-3	Plant 3 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	
TO-4	Plant 4 Thermal Oxidizer[4]	CO_2		48,369.99	48,377
		CH_4		0.15	
		N_2O		0.01	

ID No.	Description	GHG Mass Basis			CO$_2$e
			Lb/Hr	TPY[1, 2]	TPY[1, 2]
FS-800	Plant Flare, Compressor Engine Blowdown/Starter Vents to Flare	CO$_2$		3,531.52	3,872
		CH$_4$		16.10	
		N$_2$O		0.01	
TL-FLARE	Truck Loading Flare (Controlled Condensate Loading)	CO$_2$		893.20	893
		CH$_4$		0.001	
		N$_2$O		0.001	
H-741	Stabilization Unit Heater	CO$_2$		2,969.42	2,972
		CH$_4$		0.06	
		N$_2$O		0.006	
Totals		**CO$_2$**		**602,126.23**	**602,888**
		CH$_4$		**24.29**	
		N$_2$O		**0.79**	

1. Compliance with the annual emission limits (tons per year) is calculated on a 12-month rolling basis, and is recalculated each month.
2. The tpy emission limits specified in this table are not to be exceeded for this facility and includes emissions from the facility during all operations and includes MSS activities.
3. Dual-drive engines have a combined gas-fired operating limit of 28,000 hours combined. The short term lb/hr limit applies to each engine during gas fired operation. The TPY limit is for all 8 units combined.
4. The emission limit for the Thermal Oxidizers has been adjusted to allow for a 10% increase of emissions over the calculated PTE to allow for process gas variability. Emission calculations are based on a representative sample for current conditions and may change.

B. Requirements for Compressor Engines

1. Work Practice and Operational Requirements

a. Refrigeration compressor engines (C-161, C-1611, C-1612, C-162, C-1621, C-1622, C-163, C-1631, C-1632, C-164, C-1641, and C-1642) will be powered by electricity and therefore will not emit GHG.

b. Inlet compressor engines (C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, and C-4100B) are dual-drive engines capable of being powered by electricity or natural gas. The engines shall be operated using electricity no less than 60% of the time in operation once the appropriate level of electrical power is supplied to the facility.

c. The eight inlet compressor engines will have a combined maximum natural gas-fired limit of 28,000 hours in any consecutive 365 day period, recalculated each day. Daily records of the hours of operation firing natural gas must be maintained.

d. Residue compressor engines (C-1121A, C-1121B, C-1121C, C-2121A, C-2121B, C-2121C, C-3121A, C-3121B, C-3121C, C-4121A, C-4121B, and C-4121C) will be equipped with natural gas-fired engines.

e. All gas-fired engines (inlet and residue compression) will be lean-burn with low NO_x technology (with selective catalytic reduction - SCR on residue compression engines) and will be operated using good combustion practices, such as maintaining a written site specific operating procedure, maintaining equipment, and other practices that result in improved operation of the equipment.

f. All engines (C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, C-4100B, C-1121A, C-1121B, C-1121C, C-2121A, C-2121B, C-2121C, C-3121A, C-3121B, C-3121C, C-4121A, C-4121B, C-4121C, C-161, C-1611, C-1612, C-162, C-1621, C-1622, C-163, C-1631, C-1632, C-164, C-1641, and C-1642) will be tuned once per year, following vendor recommendations, for optimal thermal efficiency.

g. Permittee shall calculate the amount of CO_2 emitted from combustion in tons/yr using equation C-2a in 40 CFR Part 98 Subpart C for all compression engines identified in B.1.f. on a monthly basis.

h. Permittee shall calculate the CH_4 and N_2O emissions on a 12-month rolling average. 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).

i. Permittee shall calculate the CO_2e emissions on a 12-month rolling average, 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).

j. Fuel for the Compressor Engines shall be limited to 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 gross calorific value for a period of five years. Upon request, Permittee shall provide a sample and/or analysis of the fuel that is fired in the Compressor Engines or shall allow a sample to be taken by EPA for analysis.

k. 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.

2. Compressor Engine BACT Emission Limits

a. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from Plant I (C-1100A, C-1100B, C-1121A, C-1121B, and C-1121C) in excess of 1,871.7 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition B.1.j. and divide by the measured daily natural gas output from Plant I (MMSCFD).

b. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from Plant II (C-2100A, C-2100B, C-2121A, C-2121B, and C-2121C) in excess of 1,871.7 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition B.1.j. and divide by the measured daily natural gas output from Plant I (MMSCFD).

c. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from Plant III (C-3100A, C-3100B, C-3121A, C-3121B, and C-3121C) in excess of 1,871.7 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition B.1.j. and divide by the measured daily natural gas output from Plant I (MMSCFD).

d. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from Plant IV (C-4100A, C-4100B, C-4121A, C-4121B, and C-4121C) in excess of 1,871.7 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition B.1.j. and divide by the measured daily natural gas output from Plant I (MMSCFD).

3. Requirements during Compressor Engine Startup and Shutdown

a. Permittee shall minimize emissions during start-up and shutdown activities by operating and maintaining the facility and associated air pollution control equipment in accordance with good air pollution control practices, safe operating practices, and protection of the facility.

b. Each inlet and residue compressor engine, as listed above, has an associated starter vent. The emissions from the starter vent shall be routed to a flare (FS-800) for combustion.

c. Engine startups are limited to 30 minutes, once per hour, and 200 times per year for inlet and residue compressor engines. See Section III.A.e.

d. Each inlet and residue compressor engine, as listed above, is equipped with a blowdown vent. These emissions are re-routed back to the inlet suction when possible. The blowdown emissions are able to be rerouted to the inlet suction as long as the pressure generated by the blowdown is not greater than the inlet suction pressure. When the amount generated by the blowdown, exceeds the inlet suction pressure, the excess emissions are routed to flare (FS-800) for combustion.

e. Engine blowdowns are limited to 30 minutes, once per hour, and 72 times per year per inlet/residue compressor engine. See Section III.A.f.

C. Requirements for Heaters

1. Heater Work Practice and Operational Requirements

a. Each of the four plants has one hot oil heater rated at 48.45 million British thermal units per hour (MMBtu/hr) (H-1706, H-2706, H-3706, and H-4706) and a trim heater rated at 17.4 MMBtu (H-7810, H-7811, H-7812, and H-7813). Each TEG dehydration unit uses heat provided by direct fire from a natural gas-fired heater rated at 3 MMBtu/hr (H-7410, H-7411, H-7412, and H-7413). Each molecular sieve also has a regeneration heater rated at 9.7 MMBtu/hr (H-7820, H-7821, H-7822, and H-7823). The site also has a natural gas-fired stabilization unit heater (H-741) rated at 5.8 MMBtu/hr for the existing facility.

b. Permittee shall calculate, on a monthly basis, the amount of CO_2 emitted from combustion in tons/yr using equation C-2a in 40 CFR Part 98 Subpart C. Compliance shall be based on a 12 month 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).

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 October 30, 2009 (74 FR 56395).

e. Fuel for the heaters shall be limited to 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. Permittee shall install and maintain an operational non-resettable elapsed time meter for the heaters. The flow meters must be calibrated on an annual basis.
g. 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.
h. The heaters will be equipped with low-NO_x staged/quenching (flue gas recirculating) burners with burner management systems except for the existing unit H-741.
i. The heaters shall be tuned for thermal efficiency on an annual basis.
j. 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 Limits

a. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from Plant I (H-1706, H-7810, H-7820, and H-7410) in excess of 1102.5 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition C.1.e. and divide by the measured daily natural gas output from Plant I (MMSCFD).
b. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the Plant II (H-2706, H-7811, H-7821, and H-7411) in excess of 1102.5 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition C.1.e. and divide by the measured daily natural gas output from Plant II (MMSCFD).
c. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the Plant III (H-3706, H-7812, H-7822, and H-7412) in excess of 1102.5 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition C.1.e. and divide by the measured daily natural gas output from Plant III (MMSCFD).
d. On or after the date of initial startup, Permittee shall not discharge or cause the discharge of emissions from the Plant IV (H-4706, H-7813, H-7823, and H-7413) in excess of 1102.5 lbs CO_2/MMSCF on a 365-day rolling average. To determine this BACT emission limit, Permittee shall calculate the limit based on the

measured input mass rate of CO_2 from the natural gas GCV analysis required in Special Condition C.1.e. and divide by the measured daily natural gas output from Plant IV (MMSCFD).

D. Thermal Oxidizer Emission Sources

1. Thermal Oxidizer Work Practice and Operational Requirements

a. Each of the four plants is equipped with a thermal oxidizer (TO-1, TO-2, TO-3, and TO-4). GHG emissions from the thermal oxidizers result from fuel gas combustion (pipeline quality natural gas) and waste gas combustion (waste gas from amine units and dehydration units).
b. Each thermal oxidizer is designed to combust low-VOC concentration waste gas from the amine units and the TEG dehydration units, and has a fuel rating of 7 MMBtu/hr when firing natural gas.
c. Each thermal oxidizer shall have an initial stack test, and annual compliance testing, to verify destruction and removal efficiency (DRE) of at least 99.9%.
d. Each plant is equipped with an amine unit (F-1117, F-2117, F-3117, and F-4117). The waste gas from each amine regenerator is routed to a thermal oxidizer for combustion.
e. Each plant is equipped with a TEG dehydration unit (F-1527, F-2527, F-3527, and F-4527). The waste gas from each dehydration unit is routed to a thermal oxidizer for combustion.
f. For burner combustion, natural gas fuel usage (scf) is recorded using an operational non-resettable elapsed flow meter at each thermal oxidizer.
g. The flow rate of the waste gas combusted shall be measured and recorded using an operational non-resettable elapsed flow meter at each thermal oxidizer.
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. Permitee 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 thermal oxidizer 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 1,400 ºF at all times when processing waste gases from the amine units and dehydration units 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.
l. The thermal oxidizers' 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.

m. Oxygen analyzers shall continuously monitor and record oxygen concentration when waste gas is directed to the thermal oxidizers. 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).

E. Flare Emission Sources

1. Flare Work Practice and Operational Requirements

a. The site has pressure vessels equipped with a vapor recovery unit (VRU) system. Emissions captured by the VRU shall be routed to the truck loading flare (TL-Flare).
b. MSS emissions from the compressor engines shall be vented to a flare (FS-800).
c. Flares shall have a minimum destruction and removal efficiency (DRE) of 98% based on flowrate and gas composition measurements as specified in 40 CFR Part 98 Subpart W § 98.233(n).
d. Flares (TL-Flare and FS-800) are intermittent use MSS flares, not continuous process flares. Emission Units, FS-800 and TL-Flare, shall only combust pilot gas as a continuous stream.
e. Both flares are air assisted.
f. 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 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.
g. Each 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.

F. Fugitive Emission Sources

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. For emission units P1-FUG, P2-FUG, P3-FUG, P4-FUG, and STAB-FUG, CH_4 emissions shall be calculated annually. Emissions shall be calculated annually based on the emission factors from Table W-1A of 40 CFR Part 98, Subpart W, Petroleum and Natural Gas Systems and using the reduction credit from 28LAER and calculations given in the TCEQ Technical Guidance Document for Equipment Leak Fugitives, dated October 2000.

III. 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. Annual fuel sampling for natural gas, quarterly fuel sampling of waste gas; and
d. The daily natural gas processing rate for each plant.
e. Record the number and duration of start-ups for each engine.
f. Record the number and duration of blowdowns for each engine.

B. Permittee shall maintain the daily production volumes of residue natural gas for each plant in million standard cubic feet per day (MMSCFD). 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 year, the permittee will obtain an updated analysis of the inlet gas to document the CO_2 and methane content of the gas streams.

E. At least once per quarter, the permittee will obtain an updated analysis of the waste gas from each amine unit and each TEG dehydrator 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 and TEG dehydration unit regenerator vent emissions, Higher Heating Value (HHV), and Lower Heating Value (LHV).

F. 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).

G. 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.

H. 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; annual tuning of engines and heaters; all records relating to performance tests and monitoring of combustion equipment; 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.

I. Permittee shall maintain records that include the following: the occurrence and duration of any startup, shutdown, or malfunction, performance testing, calibrations, checks, duration of any periods during which a monitoring device is inoperative, and corresponding emission measurements.

J. Permittee shall maintain records for 5 years from the event that includes the duration of startup, shutdown, the initial startup period for the emission units, pollution control units, malfunctions, performance testing, calibrations, checks, maintenance and duration of an inoperative monitoring device and emission units with the required corresponding emission data.

K. 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. See general permit condition I.D. on page 5 of this permit. 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;
    4. Any failure to conduct any required source testing, monitoring, or other compliance activities; and
    5. Any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator or fire pump.

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

M. 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.

N. 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.

IV. Burn-in Periods

The compressor engine emission limits and requirements in conditions II.A and II.B shall not apply during combustion “burn-in” periods. Burn-in is defined as the period during initial startup, during which the Permittee conducts its initial operational and contractual testing and tuning to ensure the safe, efficient and reliable operation of the plant. The burn-in period shall not exceed 124 hours. The requirements of special condition I.C. of this permit shall apply at all times.

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 C-1100A, C-1100B, C-2100A, C-2100B, C-3100A, C-3100B, C-4100A, C-4100B, C-1121A, C-1121B,C-1121C, C-2121A, C-2121B, C-2121C, C-3121A, C-3121B, C-3121C, C-4121A, C-4121B, C-4121C, H-1706, H-2706, H-3706, H-4706, H-7810, H-7811, H-7812, and H-7813 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 engines and 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 flow rates that are comparable to the normal operating flow rates.

E. Fuel sampling for emission units TO-1, TO-2, TO-3, TO-4, and FS-800 shall be conducted in accordance with 40 CFR Part 98.

F. The holder of this permit shall perform initial performance demonstration testing of thermal oxidizers at the site. The thermal oxidizers 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.

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 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.

H. For thermal oxidizers the sampling sites and velocity traverse points 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. Each compressor engine shall be tested at maximum capacity. Each tested engine load shall be identified in the sampling report. The permit holder shall present at the pretest meeting the manner in which stack sampling will be executed in order to demonstrate compliance with the emissions limits contained in Section II.

J. The permittee shall conduct evaluations of engine performance on a quarterly basis, based on the calendar year, by measuring the CH_4 and CO_2 content of the exhaust. After four consecutive acceptable quarterly tests, the engine testing schedule may be changed to semiannually, with at least four months between tests.

K. 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.

L. 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.

L. 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.

M. 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.

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