Statement of Basis
Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Lone Star NGL Fractionators, LLC, Mont Belvieu Gas Plant

Permit Number: PSD-TX-110274-GHG

March 2014

This document serves as the Statement of Basis (SOB) for the above-referenced draft permit, as required by 40 CFR 124.7. This document sets forth the legal and factual basis for the draft permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, that would apply if the permit is finalized. This document is intended for use by all parties interested in the permit.

I. Executive Summary

On June 07, 2013, Lone Star NGL Fractionators, LLC (Lone Star) Mont Belvieu Gas Plant submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions to authorize construction of a natural gas liquids (NGL) processing plant (FRAC III Plant) and associated equipment (the Project) at the Mont Belvieu Gas Plant (Site). 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. In connection with the same proposed construction project, Lone Star submitted a new source review (NSR) and non-attainment new source review (NNSR) permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on May 17, 2013. After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize construction of air emission sources at the Lone Star FRAC III Plant.

This SOB documents the information and analysis EPA used to support the decisions EPA made in drafting the air permit. It includes a description of the proposed modification to the facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

EPA Region 6 concludes that Lone Star's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable air permit regulations. EPA's conclusions rely upon information provided in the permit application, supplemental information provided by Lone Star at EPA's request, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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

Physical Address:
9850 FM 1942
Baytown, TX 77521

Contact:
Jeff Weiler
Senior Environmental Manager
Lone Star NGL Fractionators LLC
(210) 403-7323

III. Permitting Authority

On May 3, 2011, EPA published a federal implementation plan that makes EPA Region 6 the PSD permitting authority for the pollutant GHGs. 75 FR 25178 (promulgating 40 CFR § 52.2305). The State of Texas still retains approval of its plan and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.
The GHG PSD Permitting Authority for the State of Texas is:

EPA, Region 6
1445 Ross Avenue
Dallas, TX 75202

The EPA, Region 6 Permit Writer is:
Nevine Salem
Air Permitting Section (6PD-R)
(214) 665-7222

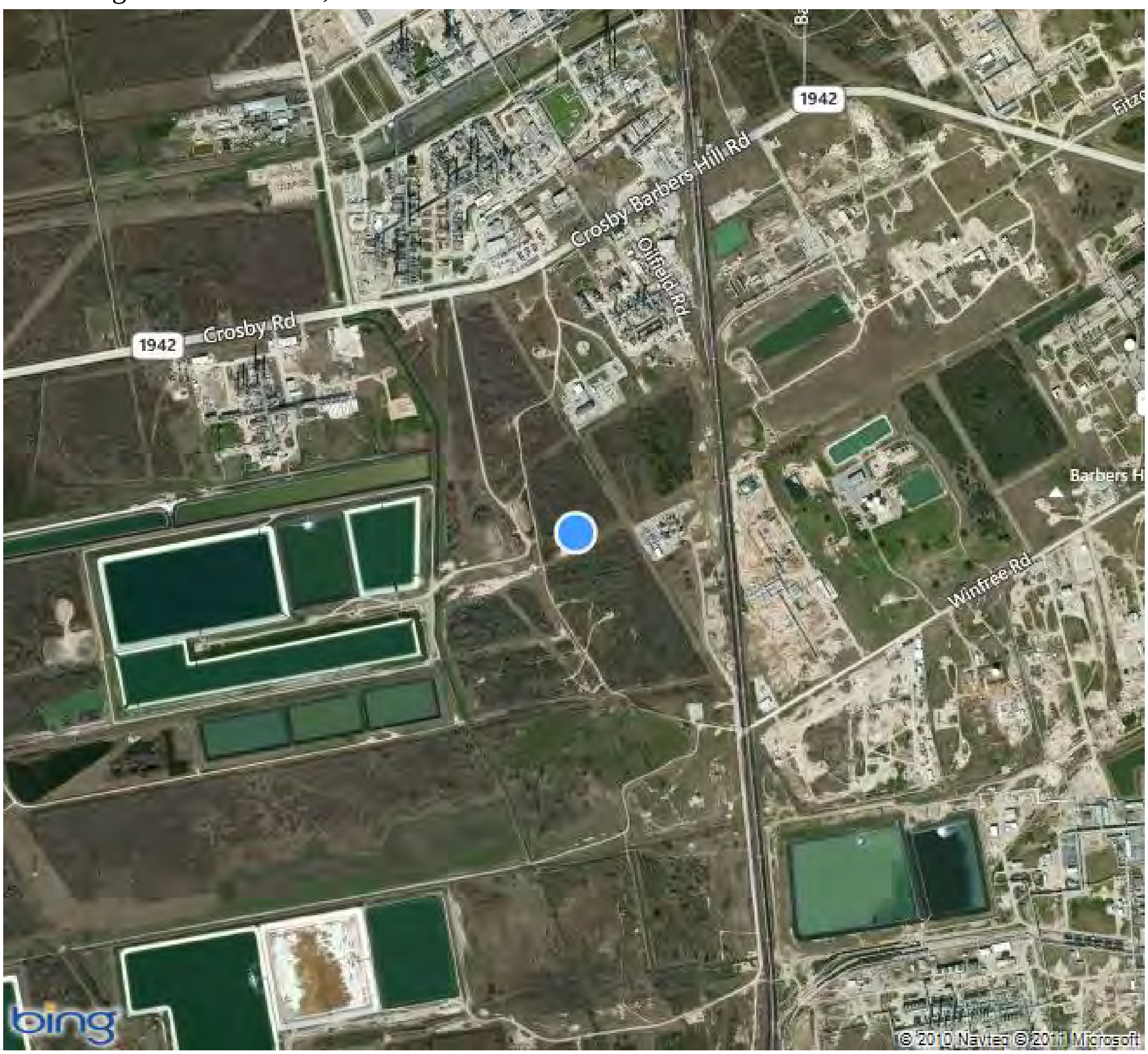
IV. Facility Location

The Lone Star, Mont Belvieu Complex is located in Chambers County, Texas, and this area is currently designated "nonattainment" for Ozone. The nearest Class 1 area is the Caney Creek Wilderness, which is located over 300 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 51' 0" North
Longitude: -94º 54'37" West

Below, Figure 1 illustrates the facility location for this draft permit.

Figure 1. Lone Star, Mont Belvieu Gas Plant Location



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

EPA concludes Lone Star NGL's application is subject to PSD review for the pollutant GHGs, because the project would lead to an emissions increase of GHGs for a facility as described at 40 CFR § 52.21(b)(49)(v). Under the project, the source is an existing minor source for PSD and the modification alone exceeds the threshold of 100,000 tpy CO_2e (equals or exceeds 100/250 TPY GHG mass basis). Lone Star NGL calculates CO_2e emissions of 218,220 tpy. EPA Region 6 implements a GHG PSD FIP for Texas under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.2305.

As the permitting authority for regulated NSR pollutants other than GHGs, TCEQ has determined the modification is not subject to PSD review for non-GHG pollutants, because the Project-related increases in CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 emissions will be less than their respective PSD significance thresholds. On May 17, 2013 Lone Star submitted an NNSR Permit for NO_X and VOC and for a minor source permit for CO, NO_X, PM, PM_{10}, $PM_{2.5}$, and SO_2 (TCEQ Air Permit No. 110274).[1] Therefore, GHGs are the only pollutant undergoing PSD review under EPA authority. Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portions of the permit and EPA will issue the GHG portions.

EPA Region 6 applies the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011). Consistent with that guidance, we have not required the applicant to model or conduct ambient monitoring for GHGs, and we have not required any assessment of impacts of GHGs in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Lone Star to construct a fractionation plant (FRAC III Plant) in Mont Belvieu. The new plant will operate to separate the NGL into the constituent gas products, which include purity ethane, propane, butanes, and natural gasoline, for sale to customers. The FRAC III Plant will process approximately 100,000 barrels per day each based on a Y-grade Natural Gas Liquids, of which ethane and propane are the major components, with heavier components making up the minor fraction.

NGL feed will enter the FRAC III Plant and pass through a closed loop amine unit. The amine unit will use amine contactors to remove CO_2 and H_2S impurities from the NGL stream. Some

---

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting Authorities, April 19, 2011, http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

hydrocarbons will also be absorbed in the process as well. The saturated (rich) amine will enter a flash tank where gaseous vapors will be flashed and recycled back to the plant fuel gas system. After the flash tank, the liquid stream (rich amine) will be routed to an amine regenerator, where heat from the FRAC III Plant's heating oil system will volatilize the remaining CO_2, H_2S, and hydrocarbons (primarily VOC) from the rich amine stream. The resulting lean amine will be returned to the amine contactors for reuse. Waste gas from the amine regenerator, which is composed of CO_2, H_2S, and VOC, will be routed to the thermal oxidizer (TO) for combustion of H_2S and VOC, and the combustion will generate SO_2 and additional CO_2 emissions. The amine unit flash tank emissions will also be sent to the TO. The TO will have a fuel firing rate of five (5) million British thermal units per hour (MMBtu/hr) and destruction efficiency (DRE) of 99.9% for VOC and H_2S, which it will achieve by maintaining a combustion chamber temperature of or above 1,400^{o}F. The TO will generate combustion-related GHG emissions. The amine unit will result in a small amount of GHG emissions from fugitive equipment component leaks, which will be controlled by implementation of an LDAR program.

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. A regeneration heater will heat a small amount of natural gas that is slip-streamed from the natural gas stream as needed to regenerate the sieve beds. The gas will then be routed back into the system inlet. There are two beds in the molecular sieve design, and beds will be regenerated one at a time. The molecular sieve unit will not have vents to the atmosphere. The wet gas from the beds during regeneration will be routed back to the system. 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. At the bottom of each column will be a reboiler that will be heated by the plant's heating oil system. As the NGL stream enters a column in the middle, the reboiler will vaporize a portion of the feed to produce stripping vapors rising inside the column. The stripping vapors will rise up through the column, contacting down-flowing liquids and allowing for the fractionation of the liquids. Vapor leaving the top of the columns will enter a condenser where heat is removed by a cooling medium and the vapor condensed. Liquid will be returned to the column as reflux to limit the loss of heavy components overhead. The product leaving the lower part of the column will have the highest boiling point, whereas the hydrocarbon leaving the top of the column will have the lowest boiling point. The separated streams (ethane, propane, butanes, and natural gasoline) will be sent via pipeline to off-site storage for pending sale to customers. No GHG emissions will be generated from the product columns, 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 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. The hot-oil system will be a network of piping that circulates hot oil through, and provides heat as needed in, various areas of the FRAC III Plant. The hot-oil system will utilize a 215 MMBtu/hr gas-fired heater. The heater will be equipped with Next Generation Ultra-Low NO_X Burners (NGULNB), or manufacturer equivalent, and will be further controlled by a Selective Catalytic Reducer (SCR) to significantly reduce NO_X emissions. The combustion of fuel gas (pipeline quality natural gas and/or ethane product) in the hot-oil heater will result in combustion-related GHG emissions. Additionally, the Molecular Sieve regeneration heater will be a 59 MMBtu/hr gas-fired heater. The two process heaters' exhausts will be routed to individual SCR abatement devices.

An existing air-assisted flare will be used to control emergency process releases and streams resulting from maintenance, startup, and shutdown (MSS) activities, and piping vents from FRAC III Plant processes. 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 and fugitive hydrocarbon streams. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 98%.

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

Fugitive emissions of GHG pollutants, including CO_2 and methane, may result from piping equipment leaks. The piping components that may leak include valves, flanges, pump seals, etc. Lone Star will implement the TCEQ 28LAER leak Detection and Repair (LDAR) program for the entire site's VOC stream and fuel-gas stream to control leaks, thereby controlling GHG emissions.

VII. General Format of the BACT Analysis

EPA conducted the BACT analysis for this draft permit by following the "Top-Down" BACT approach recommended in EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011) and earlier EPA guidance. The five steps in top-down BACT process are listed below.

(1) Identify all potentially available control options;
(2) Eliminate technically infeasible control options;
(3) Rank remaining control technologies;
(4) Evaluate the most effective controls and document the results; and
(5) Select BACT.

VIII. Applicable Emission Units and BACT Discussion

Lone Star's GHG emissions sources are divided into two categories: stack GHGs (including process-related and combustion-related GHGs) and fugitive GHGs. The majority (nearly 75%) of the the FRAC III Plant's GHGs will be from the fuel gas-fired combustion sources (i.e. heaters, flares, and thermal oxidizer). The amine unit regenerator vent CO_2 constitutes the second largest contributor, and the piping component leaks (i.e., fugitive emissions) and diesel-fired engines will contribute a minor amount of GHGs (0.2%) of the total project CO_2e emissions of 218,220 ton/yr. Stationary combustion sources primarily emit CO_2, and small amounts of N_2O and CH_4. The following devices are subject to this GHG PSD permit:

Description	EPN	FIN
Hot Oil Heater	3HR15.001	3HR15.001
Regeneration Heater	3HR15.002	3HR15.002
Thermal Oxidizer	3SK25.002	3SK25.002, 3HT16.005
Plant Flare	1SK25.001	1SK25.001
Fugitives	3FUG	3FUG
Emergency Diesel Generator 1	3GEN.001	3GEN.001
Emergency Diesel Generator 2	3GEN.002	3GEN.002
Fire Water Pump Engine	3PM18.044	3PM18.044
Miscellaneous Maintenance	3MSS1	3MSS1

IX. Project-wide GHG Controls

Lone Star performed a BACT analysis on GHG control technologies that could be implemented for this project. The BACT analysis for project-wide GHG emission reductions focuses on two control options: energy efficiency measures and carbon capture and sequestration (CCS).

Energy Efficiency Consideration:

Energy efficient technologies in the BACT analysis will help reduce the production of GHGs and other regulated air pollutants. Lone Star will use good combustion practices and energy efficient technologies and policies on each emission unit associated with the FRAC III Plant. Proper operation involves providing the proper air-to fuel ratio, residence time, temperature, and combustion zone turbulence essential to maintaining low GHG emissions. Good combustion techniques include operator practices and maintenance knowledge and practices. The proposed FRAC III Plant will install new equipment with the best engineering design and equipped with the latest technology to ensure energy efficiency.

A component of the energy efficiency technologies implemented by Lone Star is the use of electric-driven engines. Lone Star FRAC III Plant will use electric-driven engines where technically feasible. The compressors and pumps will be electric driven, resulting in no GHG emissions from these sources. Installing electric driven refrigeration compressor engines in place of gas-fired units can decrease gas losses and methane emissions. Methane emissions from gas-fired engines result from leaks in the gas supply line to the engine, incomplete combustion, and during system upsets. Electric motors reduce the chance of methane leakage by eliminating the need for fuel gas, require less maintenance, and improve operational efficiency.

Carbon Capture and Sequestration

For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology for facilities emitting CO_2 in large concentrations, including fossil fuel-fired power plants and for industrial facilities with high purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing)[2]. CCS systems involve the use of adsorption or absorption processes to remove CO_2 from flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The three main capture technologies for CCS are pre-combustion capture, post-combustion capture, and oxyfuel combustion (IPCC, 2005). Of these approaches, pre-combustion capture is applicable primarily to gasification plants, where solid fuel such as coal is converted into gaseous components by applying heat under pressure in the presence of steam and oxygen (U.S. Department of Energy, 2011). At this time, oxyfuel combustion has not yet reached a commercial stage of deployment for gas turbine applications and still requires the development of oxy-fuel combustors and other components with higher temperature tolerances (IPCC, 2005). Accordingly, pre-combustion capture and oxyfuel combustion are not considered available control options for this proposed project. The third approach, post-combustion capture, is considered potentially available technology for this source.

Once CO_2 is captured from the flue gas, CO_2 is compressed to 100 atmospheres (atm) or higher for ease of transport (usually by pipeline). The CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR). There is a large body of ongoing research and field studies focused on developing better understanding of the science and technologies for CO_2 storage.[3]

Lone Star provided a 5-step top-down BACT analysis and discussed the technical infeasibility and the economic costs and adverse environmental impacts of utilizing CCS technology, as well as an additional cost analysis provided to support this determination. As explained more fully below, EPA has reviewed Lone Star's CCS analysis and has determined that CCS is not economically

[2]U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, *PSD and Title V Permitting Guidance for Greenhouse Gases*, March 2011, <http:/www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf> (March 2011)
[3] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory *Carbon Sequestration Program: Technology Program Plan*, <http://www.netl.doe.gov/technologies/carbon_seq/refshelf/2011_Sequestration_Program_Plan.pdf>, February 2011

feasible at this time for this application and also has potential negative environmental and energy impacts, and has eliminated CCS as a BACT option.

The analysis provided by the applicant demonstrated that CCS can be eliminated based on its economic, environmental, and energy impacts. In its analysis, Lone Star noted that CO_2 separation is a vital first step for CCS. The CO_2 separation would first require the removal of particulate matter (PM) from the streams without creating too much back pressure on the upstream system (i.e. the Plant's combustion processes). Next, it would require inlet compression to increase the pressure from atmospheric levels to the minimum of 700 psi required for efficient CO_2 separation. The installation of cryogenic units or other cooling mechanisms (e.g., complex heat exchangers) would be required to reduce the temperature of the streams from over 500 ^oF to less than 100 ^oF prior to separation, compression, and transmission. The cryogenic units would each require propane compression, which could be electric-driven or gas-fired (i.e. generating additional GHG emissions).

Also the installation of an additional amine unit to capture the CO_2 from the exhaust/waste streams and a gas-fired heater to separate CO_2 from the rich amine would be required. Finally, the separated CO_2 stream would require large compression equipment to pressurize the CO_2 to transfer to the Denbury pipeline. The CO_2 compressors must be designed to handle acidic gases, with high energy consumption/cost to pressurize the CO_2 from near atmospheric pressure up to the receiving pipeline pressure to transfer offsite. To process this stream for CCS, the FRAC III Plant would need to have an additional amine unit, cryogenic units, dehydration units, and associated equipment that would exceed the footprint required for the proposed addition to the plant. If the compression were to be gas-fired, Lone Star estimates that 6 Caterpillar 3616 engines would be needed to produce 28,000 hp. Each 3616 engine will generate nearly 20,000 TPY CO_2 for a total of 120,000 tons of CO_2 just from the compression process to the dedicated amine unit. Alternatively, electric engines for a total of over 15,000 hp output would be required, significantly increasing the electrical load of the FRAC III Plant and the need to purchase additional electrical power or consider installing its own power block. Considering the additional equipment and associated emission sources utilizing natural gas, implementing CCS at the site would generate additional GHG emissions (estimated 215,935.64 T/yr) greater than PSD GHG applicability thresholds and additional $PM_{10}/PM_{2.5}$ and VOC emissions greater than PSD significance thresholds. The proposed project is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could exacerbate ozone formation in the area.

The nearest existing pipeline identified by Lone Star that may transport CO_2 is approximately 30 miles from the plant.[4] The distance to the pipeline is estimated based on the location of Denbury Green Pipeline located in Chambers County as seen from the National Pipeline Mapping System.[5]

---

[4] Figure 4-1 (CO2 Pipeline Map) Lone Star Frac III Permit application P. 40

[5] http://www.npms.phmsa.dot.gov/

Lone Star utilized the March 2010 National Energy Technology Laboratory (NETL) document *Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447*[6] to estimate the cost associated with the pipeline and associated equipment. Assuming that the CO_2 pipeline company would be able to receive the CO_2 stream, the capital costs for the CCS project associated with the additional equipment needs (to purify and compress CO_2 stream), and the pipeline to transport the CO_2 is estimated to be over $115,000,000. The FRAC III Plant total capital investment without CCS is estimated at $324,479,615. The estimated capital cost increase for implementing CCS will be approximately 35%. The total CCS annualized cost over the 10 year[7]expected life of the equipment is $17,479,949 per year. Based on an 8% interest rate, and a 10-year equipment life, the total project annualized cost (without CCS) is estimated to be $33,048,965.51 per year. Lone Star indicates that the annualized cost of CCS is approximately 50% of the annualized cost of the FRAC III Plant.

As explained above, EPA Region 6 reviewed Lone Star's CCS cost estimate[8] and believes CCS is financially prohibitive due to its overall cost as a GHG control strategy. The use of CCS on the stack GHG emissions is not economically feasible for the site. Considering the additional equipment and associated emission sources, implementing CCS at the site would generate additional GHGs greater than the major source threshold and additional $PM_{10}/PM_{2.5}$ and VOC emissions greater than PSD significance thresholds. Therefore, EPA has determined at this time that CCS should be eliminated as BACT for this facility due to the economic impacts and negative environmental and energy impacts associated with the technology.

X. Hot Oil Heater and Regeneration Heater: (EPNs: 3HR15.001 and 3HR15.002)

The Hot Oil Heater and the Regeneration Heater at the FRAC III Plant will be fired on fuel gas (pipeline-quality natural gas and/or ethane product). The Hot Oil Heater (FIN: 3HR15.001) will be rated at 215 MMBtu/hr. The Regeneration Heater (FIN: 3HR15.002) will be rated at 59 MMBtu/hr. The heaters will be operated with NGULNB, or manufacturer equivalent, and will be controlled further with individual SCR devices (EPNs: 3HR15.001 and 3HR15.002). Periods of startup and shutdown will be limited to one hour for each type of event and 50 hr/yr for all MSS hours combined.

---

[6] See Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs available at http://www.netl.doe.gov/energy-analyses/pubs/QGESStransport.pdf

[7] Plant life time is estimated at 20 years, due to the normal plant lifetime expectations. However, Lone Star estimated the cost based on CCS equipment life anticipated to be 10 years based upon extreme acidic conditions of the CO_2 stream.

[8] See the CCS cost analysis at Table (4-5) of the permit application.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture and Storage (CCS)* – CCS is an available add-on control technology that is applicable for all of the sites' affected combustion units.
- *Fuel selection/switching:* Non-emergency equipment will be firing only pipeline-quality natural gas and/or ethane product, which results in 28% less CO_2 production than fuel oils.
- *Good Combustion Practices:* Techniques include operator practices, maintenance knowledge, and maintenance practices to control the formation of GHGs emissions.
- *Burner management systems:* The heaters will be equipped with burner management systems that will include intelligent flame ignition, flame intensity controls, and flue gas recirculation.
- *Periodic tune-ups and maintenance for optimal thermal efficiency:* Periodic tune-ups will increase the efficiency of the equipment. Maintenance will be performed routinely per vendor recommendations of the facility's maintenance plan, and replacing or servicing components will be performed as needed. Lone Star will tune the heaters once a year for optimal thermal efficiency.
- *Fuel gas pre-heating:* Preheating the fuel stream reduces the heating load, increases thermal efficiency, and therefore reduces emission.
- *Air to fuel ratio controllers:* Oxygen monitors and intake flow monitors can be used to optimize the fuel/air mixture and limit excess air and reduce the amount of energy required to heat the steam and, therefore, reduce the CO_2e emissions. The heaters' air and fuel valves will be mechanically linked to maintain the proper air to fuel ratio;
- *Heat Recovery*: The hot effluent form the hot oil heater will be cooled in the primary and secondary heat exchangers that heat the hot oil heater will be cooled in the primary and secondary heat exchangers that heat the hot oil (heart transfer medium for the FRAC III Plant) to recover this energy and reduce the overall energy use in the plants. Tertiary exchangers will also recover heat and contribute to overall energy efficiency. Finally, the combustion convective section will be used to pre-heat the hot oil to the extent that the final exiting flue gas temperature is reduced to its practical limit.
- *Energy efficiency*: High efficiency and variable speed drives reduce electricity consumption by 4-17 % when compared to standard motors and fixed speed drives.
- *Proper Heater Operation:* Proper operation involves providing the proper air to fuel ration, residence time, temperature, and combustion zone turbulence essential to maintain low emissions.
- Limit of start-up operation to 1 hour for the heaters.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 for the Hot Oil Heaters are considered technically feasible for this project, except preheating fuel stream for heaters because Lone Star will be using more efficient burner management systems, which include flue-gas recirculation, and achieve a higher overall combustion efficiency.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Control Technology	***Estimated GHG % Reduction***
• CCS	80
• Fuel selection/switching (natural gas versus No.2 Fuel Oil)	28
• Burner management systems	10-25
• Fuel gas pre-heating	10-15
• Energy efficiency	4-17
• Proper Heater Operation	1-15
• Annual tune-ups and maintenance for optimal thermal efficiency	1-10
• Heat Recovery	2-4
• Air to fuel ratio controllers	1-3
• Good Combustion Practices	-

Good heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from the *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, issued by EPA in October 2010.[9] Product heat recovery involves the use of heat exchangers to transfer the excess heat that may be contained in product streams to feed streams.

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

Carbon Capture and Storage

This add-on control technology was already discussed in detail in section IX. Based on the economic infeasibility and negative energy and environmental impacts discussed in section IX above, CCS will not be considered further in this analysis.

Fuel Selection Switching

Firing a low carbon fuel reduces the CO_2 production form combustion. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

---

[14] Available at http://www.epa.gov/nsr/ghgdocs/refineries.pdf

Combustion Air Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall heater efficiency. Manual or automated air/fuel ratio controls is used to optimize these parameters and maximize the efficiency of the combustion process. Automated controls are considered more efficient than manual controls. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Periodic Tune-up

Periodic tune-ups of the heaters include:

Preventative maintenance check of fuel gas flow meters annually,

- Preventative maintenance check of oxygen control analyzers quarterly,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range, and routine and proper maintenance can theoretically recover up to 10% of the efficiency lost overtime to age. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Heater Design

New heaters can be designed with efficient burners, more efficient heat transfer efficiency to the hot oil and regeneration streams, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Heat Recovery

Rather than increasing heater efficiency, the technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Proper Operation and Good Combustion Practices

Proper operation involves providing the proper air-to-fuel ration, residence time, temperature and combustion zone turbulence essential to maintain low GHG emissions. Good combustion techniques include: operator practices; maintenance knowledge; and proper maintenance and tune-up of the heaters at least annually per the manufacturer's specification. No cost, energy, or environmental impacts warrant this option's elimination as BACT.

Step 5 – Selection of BACT

To date, other similar facilities with a GHG BACT limit are summarized in the table below:

Company/ Location	Process Description	BACT Control(s)	BACT Emission Limit/Requirements	Year Issued	Reference
Enterprise Products Operating LLC, Eagleford Fractionation and DIB Units Mont Belvieu, TX	NGL Fractionation 2 Hot Oil Heaters (140 MMBtu/hr each) 2 Regeneration Heaters (28.5 MMBtu/hr each)	Energy Efficiency/Good Design & Combustion Practices	Hot Oil Heaters have a minimum thermal efficiency of 85% on a 12-month rolling basis. Regeneration Heaters with good combustion practices.	2012	PSD-TX-1286-GHG
ONEOK Hydrocarbon LP, Mont Belvieu, TX	NGL Fractionation 3 Hot Oil Heaters (154 MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	Hot Oil Heaters – 14.25 lb CO_2/bbl of Y-grade NGL processed for all 3 heaters combined	2013	PSD-TX 106921-GHG
Energy Transfer Partners, Lone Star NGL Mont Belvieu, TX	NGL Fractionation 2 Hot Oil heaters (270 MMBtu/hr each) 2 Regeneration Heaters (46 MMBtu/hr)	Energy Efficiency/Good Design & Combustion Practices	Hot Oil Heaters- 7.6 lb CO_2/bbl of NGL processes per heater. Regenerator Heaters-1.3 lbs CO_2/bbl of NGL processed per heater. 365 day rolling average.	2012	PSD-TX-93813
Targa Midstream Services LLC, Mont Belvieu Plant Mont Belvieu, TX	2 Hot Oil Heaters (144.45 MMBtu/hr)	Energy Efficiency/Good Design & Combustion Practices	GHG BACT limit for oil heaters of 4.06 lb CO_2/bbl NGL processed per heater	2013	PSD-TX-101616
Energy Transfer Company (ETC), Jackson County Gas Plant Ganado, TX	Natural Gas Processing Plants 4 Hot Oil Heaters (48.5 MMBtu/hr each) 4 Molecular Sieve Heaters (9.7 MMBtu/hr each) 4 Regeneration Heaters (3MMBtu/hr each)	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT limit for process heaters of 1,102.5 lbs CO_2/MMscf 365-day average, rolling daily for each plant Fugitive methane emissions are monitored and maintained using best practice standards.	2012	PSD-TX-1264-GHG

The BACT determination for all the above-referenced facilities apply to natural gas liquids (NGL) fractionation.

Hot Oil Heaters:

Lone Star FRAC III Plant, Targa Mont Belvieu, and Energy Transfer Partners – Lone Star NGL produce a similar higher grade of propane (+95%) for export purposes, which requires higher heat duties than Enterprise Eagleford Fractionation facility. Similar to ONEOK's proposed design, the heat for the regeneration process is provided by the hot oil system with no separate regeneration heaters. Energy Transfer Partners – Lone Star NGL facility, Targa Midstream, and ONEOK Mont Belvieu NGL plant proposed output-based limits. Targa Midstream has two oil heaters with 144.45 MMBtu/hr with an output-based BACT limit of 4.06 lbCO2/bbl of NGL processed per heater. The two hot oil heaters at the Energy Transfer Partners-Lone Star NGL facility each have a heat input rate of 270 MMBtu/hr and an output-based BACT limit of 7.6 lb CO_2/bbl of NGL processed. Lone Star proposes to install one hot oil heater with 215 MMBtu/hr at the FRAC III Plant with a proposed output-based BACT limit of 7.12 lb CO_2/bbl of NGL processed.

Regeneration Heaters:

The regeneration heater proposed by Lone Star is rated at 59 MMBtu/hrbr. This falls within the range of previously permitted regeneration heaters identified in the table above. The regeneration heater will be equipped with NGULNB, or manufacturer equivalent, and will be further controlled by an SCR system. Between regeneration cycles, the heater's firing rate is reduced to a maintenance level. However, Lone Star has assumed the heater fires at maximum capacity year round (8,760 hr/yr). Periods of startup and shutdown will be limited to one hour for each type of event and 50hr/yr for all MSS hours combined.

EPA analyzed the BACT limits proposed by the applicant and has determined that they are consistent with other BACT determinations for similar units and are consequently a reasonable estimation of BACT.

The following specific BACT practices are proposed for the heaters:

- *Heater design* – The hot oil heaters and regeneration heaters shall be designed to achieve high thermal efficiencies.
- *Heater design* – Burner design improves the mixing of fuel, creating a more efficient heat transfer. Lone Star NGL will utilize a burner management system on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation optimize the efficiency of the devices.
- *Periodic Tune-up* – Clean burner tips and convection tubes as needed, but to occur no less frequently than every 12 months.

- *Combustion Air Controls* – Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air to 15%.
- *Fuel Selection/Switching* – Lone Star NGL will be firing only pipeline quality natural gas, which results in 28% less CO_2 production than fuel oils.
- *Heat Recovery* – Use of heat recovery from the hot effluent from the hot oil heater in the primary and secondary heat exchangers. Tertiary exchangers also recover heat and contribute to primary and secondary heat exchangers. Tertiary exchangers also recover heat and contribute to overall energy efficiency. The combustion convection section is used to preheat the hot oil.
- *Proper operation and Good Combustion Practices* – Proper operation involves providing the proper air-to-fuel ratio, residence time, temperature, and combustion zone turbulence essential maintenance knowledge; and maintenance practices.

<u>BACT Limits and Compliance:</u>

Using the BACT practices above will result in an output-based BACT limit for the heaters based on the barrels (bbl) per day of natural gas liquids processed.

The Hot Oil Heaters shall have a 7.12 lbs CO_2/barrel (bbl) processed BACT limit. The Regeneration Heaters shall have a 1.95 lbs CO_2/bbl processed BACT limit. Compliance will be determined for both limits on a 365-day rolling average.

Both the hot oil and regenerator heaters will be designed to incorporate efficiency features, including insulation to minimize heat loss and heat transfer components that maximize heat recovery while minimizing fuel use. Lone Star NGL will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters.

Lone Star NGL will demonstrate compliance with the CO_2 limits for the heaters using the emission factors for natural gas from 40 CFR Part 98 Subpart C, Table C-2. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(3)(iii) is as follows:

$$\mathrm{CO_2} = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 * 1.1023$$

Where:

CO_2 = Annual CO_2 mass emissions from combustion of natural gas (short tons)
Fuel = Annual volume of the gaseous fuel combusted (scf). The volume of fuel combusted must be measured directly, using fuel flow meters calibrated according to §98.3(i).
CC = Annual average carbon content of the gaseous fuel (kg C per kg of fuel). The annual average carbon content shall be determined using the same procedures as specified for (High Heat Value) HHV at §98.33(a)(2)(ii)

MW = Annual average molecular weight of gaseous fuel (kg/kg-mole). The annual average molecular weight shall be determined using the same procedure as specified for HHV at §98.33(a)(2)(ii).
MVC = Molar volume conversion factor at standard conditions, as defined in §98.6.
44/12 = Ratio of molecular weights, CO2 to carbon
0.001= Conversion of kg to metric tons
1.102311 = Conversion of metric tons to short tons

The proposed permit also includes an alternative compliance demonstration method, in which Lone Star may install, calibrate, and operate a CO_2 Continuous Emission Monitoring System (CEMS) and volumetric stack gas flow monitoring system with an automated data acquisition and handling system for measuring and recording CO_2 emissions.

The emission limits associated with CH_4 and N_2O are calculated based on emission factors provided in 40 CFR Part 98, Table C-2 and the actual heat input (HHV). Comparatively, the emissions from CO_2 contribute the greatest (greater than 99%) to the overall emissions from the heaters and; therefore, additional analysis is not required for CH_4 and N_2O. To calculate the CO_2e emissions, the draft permit requires calculation of the emissions based on the procedures and Global Warming Potentials (GWP) contained in the Greenhouse Gas Regulations, 40 CFR Part 98, Subpart A, Table A-1. Records of the calculations would be required to be kept to demonstrate compliance with the emission limits on a 365-day rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emissions unit. Initial stack test demonstrations for CH_4 and N_2O emissions are not required because the CH_4 and N_2O emissions are less than 0.01% of the total CO_2e emissions from the heaters and are considered a *de minimis* level in comparison to the CO_2 emissions.

XI. Thermal Oxidizers (EPN: 3SK25.002)

The FRAC III Plant will utilize a thermal oxidizer (3SK25.002) to control the waste gas vent stream from the amine unit regenerator vent. GHGs from the thermal oxidizer will result from fuel gas (pipeline-quality natural -gas and/or ethane product) and waste-gas combustion, as well as amine-unit CO_2 pass through. The thermal oxidizer will have a fuel-firing rate of five (5) MMBtu/hr and hydrocarbon destruction and removal efficiency (DRE) of 99.9 % for VOC and H_2S.

Step 1 – Identification of Potential Control Technologies

- *Use of Standard Thermal Oxidizers* **–** Use of thermal oxidizers for control of emissions.
- *Use of Other Planned Combustion Processes in lieu of a Separate Thermal Oxidizer* - Use of existing combustion processes (e.g. flare or heaters) over a separate thermal oxidizer.

- *Proper Design, Operation, and Good Combustion Practices* – Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for use of other planned combustion processes over a separate thermal oxidizer. It is not technically feasible to use the flare in lieu of the thermal oxidizer for normal operation (only upset conditions), because the flare cannot handle the volume of waste streams to be routed to the thermal oxidizer. The flare is for intermittent use only, for combusting intermittent MSS streams. Further, the waste stream has a very low heat content (<100 Btu/scf). Therefore, it is not feasible to send this stream to the proposed heaters as the stream will not combust properly and could cause mechanical problems within that heater causing inefficient operation.

Because the remaining technologies are already proposed for use at the project, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not Applicable (as noted above)

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Not Applicable (as noted above)

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the thermal oxidizer:

- *Use of Standard Thermal Oxidizers* – Lone Star will be utilizing standard thermal oxidizers with a 99.9% DRE for VOC. This type of thermal oxidizer will be used to meet stringent VOC control requirements for the Houston-Galveston-Brazoria “severe” ozone non-attainment area.
- *Proper Design, Operation, and Good Combustion Practices* – Periodic maintenance will help maintain the efficiency of the thermal oxidizer. Temperature monitoring will ensure proper thermal oxidizer operation.

Based on the identified control technologies and the proposed work practice standards, an emission limit for the thermal oxidizer of 51,357 tpy CO_2e is proposed. Compliance shall be determined by the monthly calculations of GHG emissions using equation W-3 consistent with 40 CFR Part 98, Subpart W [98.233(d)(2)]

XII. Flare (EPN: 1SK25.001)

The FRAC III Plant will utilize an existing air assisted flare (FIN: 004-FLARE, changed to FIN 1SK25.001 for TCEQ Permit No. 110274 for FRAC III plant) for control of combustion-related and uncontrolled MSS emissions and piping-vent fugitive emissions. No process streams will be routed to the flare during normal operation. The GHG PSD permit will only address the emission increase at the existing flare. The flare will have a hydrocarbon destruction and removal efficiency (DRE) of 98%.

Step 1 – Identification of Potential Control Technologies

- *Proper Operation and Good Combustion Practices* – Use of flow and composition monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and the resulting CO_2.
- *Fuel Selection* – Use of low carbon fuels such as natural gas, which represents the available pilot and supplemental fuel type with the lowest carbon intensity on a heat input basis.
- *Minimize Duration of MSS Activities* – Minimize the duration and quantity of MSS flaring to the extent possible through good engineering design of the process and good operating practices.
- *Flare Gas Recovery* – A flare gas recovery compressor system can be used to recover flared gas to the fuel gas system.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible, except for flare gas recovery. The flare is not a process flare, but an intermittent-use MSS flare. Therefore, no continuous stream is being combusted, and flare gas recovery is infeasible to implement.

Because the remaining technologies are already proposed for use at the project, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not Applicable (as noted above)

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Not Applicable (as noted above)

Step 5 – Selection of BACT

Lone Star proposes the following monitoring and work practice requirements to assist in maintaining the destruction efficiency and emission limit for the flare:

- *Fuel selection* – The proposed flare will burn pipeline quality natural gas in the pilots.
- *Proper Operation and Good Combustion Practices* –. Lone Star will only be flaring high Btu gases. Lone Star will monitor the BTU content on the flared gas, and will have air assisted combustion allowing for improved flare gas combustion and minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.
- *Minimize Duration of MSS activities* – Minimize outage time of the deethanizer and coordinate inlet filter change outs, pump/compressor maintenance, and meter recalibration in order to minimize flaring events.
- Lone Star will operate the Flare in accordance with 40 CFR 60.18, including monitoring the heating value and exit velocity, and continuously monitor for the presence of pilot flame considering infrared monitoring as equivalent to a thermocouple.

Using these BACT practices above will result in an emission limit for the low-profile flare of 396.59 tpy CO_2e.

XIII. Process Fugitives (3FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane and CO_2. The total estimated fugitive CO_2 and methane emissions have been conservatively estimated to be 15.33 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for less than 0.01% of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

The following control technologies for process fugitive emissions of CO_2e are listed below:

- *Implementation of LDAR program* – LDAR programs are designed to control VOC emissions and vary in stringency. LDAR is currently only required for VOC sources. Methane is not considered a VOC, so LDAR is not required for streams containing high content of methane. Organic vapor analyzers or infrared cameras are commonly used in LDAR programs. TCEQ's 28 LAER LDAR is currently the most stringent program, which achieve efficiencies of 97% for valves. Lone Star will implement TCEQ's LAER program on all VOC lines and the fuel gas (high methane content) in the FRAC III Plant; this program will result in a reduction of GHG emissions from these piping components; and
- *Use of low-bleed gas-driven pneumatic controllers or compressed air-driven pneumatic controllers* – Low-bleed gas-driven pneumatic controllers emit less gas (that contains GHG)

than standard gas-driven controllers, and compressed air-driven pneumatic controllers do not emit GHG.

Step 2 – Elimination of Technically Infeasible Alternatives

All technologies listed in Step 1 are technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As stated in Section XI, Step 1, this evaluation does not compare the effectiveness of different levels of LDAR programs.

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Lone Star intends to implement all technologies listed in Step 1, which together will reduce fugitive emissions by 80-90%. Because an LDAR program is being implemented for VOC control purposes at the FRAC III Plant, it will also result in effective control of the small amount of GHG emissions from the same piping components. Lone Star uses TCEQ's 28LAER[10] LDAR program at the Mont Belvieu Complex to minimize process fugitive VOC emissions at the plant, and this program has also been proposed for the additional fugitive VOC emissions associated with the project. 28LAER is TCEQ's most stringent LDAR program, developed to satisfy LAER requirements in ozone non-attainment areas.

Step 5 – Selection of BACT

EPA has reviewed and concurs with Lone Star's fugitive emission sources BACT analysis. Based on Lone Star's top-down BACT analysis for fugitive emissions, Lone Star concludes that using the TCEQ 28 LAER leak detection and repair (LDAR) program is the appropriate BACT control technology option. Lone Star also identified and adopted the use of dry compressor seals, use of rod packing, and the use of low-bleed gas-driven pneumatic controllers or air-driven pneumatic controllers as BACT for fugitives. EPA determines that the TCEQ 28LAER work practice standard for fugitives for control of CH_4 emissions is BACT. While the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of fugitive GHG emissions is not considered feasible due to their negligible amount.

XIV. Diesel-Fired Engines: Emergency Diesel Generators (EPN:3GEN.001 & 3GEN.002) and Emergency Firewater Pump (EPN: 3PM18.044)

[10] The boilerplate special conditions for the TCEQ 28LAER LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28laer.pdf. These conditions are included in the TCEQ issued NSR permit.

The FRAC III Plant will include two diesel-fired emergency generator engines (FINs: 3GEN.001 and 3GEN.002) and a diesel-fired fire water pump engine (FIN: 3PM18.044). The combustion of diesel in the emergency engines will result in combustion-related GHG emissions.

Step 1 – Identification of Potential Control Technologies

- *Selection of Energy Efficient Engines* – Selection of energy efficient engines would reduce the total heat input of the plant and the emissions associated with the engines.
- Low Carbon Fuels – Use of fuels containing lower concentrations of carbon generate less CO_2, than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal.
- *Process Controls, Limited Operation, and Maintenance Practices* – Good operating and maintenance practices include appropriate maintenance of equipment and operating within the recommended air to fuel ratio recommended by the manufacturer.

Step 2 – Elimination of Technically Infeasible Alternatives

- *Low Carbon Fuels* – The purpose of the engines is to provide a power source during emergencies, which include site power outages and natural disasters, such as hurricanes. As such, the power source must be available during emergencies. Electricity is not a source that is available during a power outage, which is the specific event during which the backup generators are designed to operate. Natural gas supply may be curtailed during an emergency such as a hurricane, thereby not providing fuel to the engines during the specific event for which the backup generators and fire water pump engine are designed to operate. The National Fire Protection Association (NFPA) requires that fire water pump engines meet the NFPA 20 Standard (Standard for the Installation of Stationary Pumps for Fire Protection). NFPA 20 doesn't allow the use of spar ignition (SI) internal combustion engines to drive fire water pumps, which would include engines that use natural gas fuel. The engines must be powered by a liquid fuel that can be stored in a tank and supplied to the engine on demand, such as motor gasoline or diesel. Therefore, Lone Star proposes to use diesel fuel for the emergency generator engines and fire water pump engines because non-volatile fuel must be used for emergency generator operation and is not considered further for this analysis.

Because the remaining technologies are already proposed for use at the project, ranking by effectiveness (Step 3) and a subsequent evaluation of each technology (Step 4) was not considered necessary for the BACT determination.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not Applicable (as noted above)

Step 4 – Evaluation of Control Technologies in Order of Most Effective to Least Effective

Not Applicable (as noted above)

Step 5 – Selection of BACT

The following specific BACT practices are proposed for the engines:

- *Selection of Energy Efficient Engines* – The selected engines are required to be available for use at any time in the event of an emergency, including when natural gas is not available.
- *Process Controls, Good Operation, and Maintenance Practices* – State of the art process instrumentation and controls will be utilized. Good operation and maintenance practices for compression ignition engines include appropriate maintenance of equipment, periodic testing, and operating within the recommended air to fuel ration, as specified by its design.

The generators and fire water pump non-emergency operation will be limited to a maximum of 36 hours per year. Annual GHG mass emission rates are estimated based on using vendor specification (447 kW and 500kW) to determine the maximum heat input. The CO_2e emissions for the two emergency generators and the fire water pump engine account for less than 0.06% of the total project emissions. Lone Star will demonstrate compliance with the CO_2 emission limit using the emission factors for diesel fuel from 40 CFR Part 98 Subpart C, Table C-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(1)(i).

XV. Threatened and Endangered Species

Pursuant to Section 7(a)(2) of the Endangered Species Act (ESA) (16 U.S.C. 1536) and its implementing regulations at 50 CFR Part 402, EPA is required to insure that any action authorized, funded, or carried out by EPA is not likely to jeopardize the continued existence of any federally-listed endangered or threatened species or result in the destruction or adverse modification of such species' designated critical habitat.

To meet the requirements of Section 7, EPA is relying on a Biological Assessment (BA) prepared by the applicant and reviewed by EPA. Further, EPA designated Lone Star NGL Mont Belvieu, L.P. ("Lone Star") and its consultant, URS, Inc., as non-federal representatives for purposes of preparation of the BA and for conducting informal consultation. . EPA is relying on the same Biological Assessment utilized for Energy Transfer Partners - Lone Star NGL FRAC II facility which was permitted by EPA in October 2012 for the Lone Star FRAC III biological assessment as they are co-located. The biological assessment performed for the Energy Transfer Partners – Lone

Star NGL FRAC II facility included in its field survey the physical land area where Lone Star FRAC III site will be built.

A draft BA has identified ten (10) species as endangered or threatened in Chambers County, Texas by the U.S. Fish and Wildlife Service (USFWS), National Marine Fisheries Service (NMFS) and the Texas Parks and Wildlife Department (TPWD) and is listed in the table below:

Federally Listed Species for Harris County	Scientific Name	Identifying Agency
Smalltooth Sawfish	*Pristis pectinata*	NMFS/TPWD
Green Sea Turtle	*Chelonia mydas*	USFWS/NMFS/TPWD
Kemp's Ridley Sea Turtle	*Lepidochelys kempii*	USFWS/NMFS/TPWD
Leatherback Sea Turtle	*Dermochelys coriacea*	USFWS/NMFS/TPWD
Loggerhead Sea Turtle	*Caretta caretta*	USFWS/NMFS/TPWD
Hawksbill Sea Turtle	*Eretmochelys imbricate*	USFWS/NMFS/TPWD
Louisiana Black Bear	*Ursus americanus luteolus*	TPWD
Red Wolf	*Canis rufus*	TPWD
Piping Plover	*Charadrius melodus*	USFWS/TPWD
Sprague's pipit*	*Anthus spragueii*	USFWS

*Sprague's' pipit is listed as a candidate species by USFWS

EPA has determined that issuance of the proposed permit will have no effect on any of the ten (10) listed species, as there are no records of occurrence, no designated critical habitat, nor potential suitable habitat for any of these species within the action area.

Because of EPA's "no effect" determination, no further consultation with the USFWS and NMFS is needed.

Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on listed species. The final draft biological assessment can be found at EPA's Region 6 Air Permits website athttp://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVI. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible or potentially eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by URS, Lone Star NGL's consultant, submitted on July 24, 2012. EPA is relying on the same Cultural Assessment utilized for Energy Transfer Partners - Lone Star FRAC II facility which was permitted by EPA in October 2012 for the Lone Star FRAC III addition as they are co-located. The Cultural Assessment performed for the Energy Transfer Partners – Lone Star NGL FRAC II facility included in its field survey the physical land area where the Lone Star FRAC III site will be built. EPA requested concurrence of "no adverse effects" from the State Historic Preservation Officer (SHPO) on August 30, 2012 and the SHPO provided concurrence on September 15, 2012

On February 10, 2014, EPA sent letters to Indian tribes identified by the Texas Historical Commission as having historical interests in Texas to inquire if any of the tribes have historical interest in the particular location of the project and to inquire whether any of the tribes wished to consult with EPA in the Section 106 process. EPA received no requests from any tribe to consult on this proposed permit.

EPA will provide a copy of the report to the State Historic Preservation Officer for consultation and concurrence with its determination. Any interested party is welcome to bring particular concerns or information to our attention regarding this project's potential effect on historic properties. A copy of the report may be found at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XVII. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive policy on environmental justice. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that environmental justice issues must be considered in connection with the issuance of federal Prevention of Significant Deterioration (PSD) permits issued by EPA Regional Offices. *See, e.g., In re Prairie State Generating Company,* 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass, Gmbh,* 8 E.A.D. 121, 174-75 (EAB 1999*) ("Knauf I").*This permitting action, if finalized, only authorizes emissions of GHGs and does not select environmental controls for any other pollutants. Climate change modeling and evaluations of risks and impacts is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an environmental justice analysis is not necessary for the permitting record.

XVIII. Conclusion and Proposed Action

Based on the information supplied by Lone Star, our review of the analyses contained the TCEQ PSD Permit Application and the GHG PSD Permit Application, and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed facility would employ BACT for GHGs under the terms contained in the draft permit. Therefore, EPA is proposing to issue Lone Star a PSD permit for GHGs for the FRAC III Plant, subject to the PSD permit conditions specified therein. This permit is subject to review and comments. A final decision on issuance of the permit will be made by EPA after considering comments received during the public comment period.

APPENDIX

Annual Facility Emission Limits

Annual emissions, in tons per year (TPY) on a 365-day rolling average, shall not exceed the following:

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
3HR15.001	3HR15.001	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	3HR15.002	FRAC III Regenerator Heater (normal operations)	CO_2	35,686	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	396	397	Good combustion practices. See permit condition III.B.4
			CH_4	No Emission Limit Established[4]		
			N_2O			
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[4]	No Emission Limit Established[5]	Implementation of LDAR Program. See Permit condition III.B.6
			CH_4			
			N_2O			
3GEN.001	3GEN.001	FRAC III Emergency Diesel Generator 1	CO_2	14.96	15	Good combustion practices, non-emergency operation limited to 36 hrs/yr. See Permit conditions
			CH_4	No Emission Limit Established[4]		
			N_2O			
3GEN.002	3GEN.002	FRAC III Emergency Diesel Generator 2	CO_2	16.73	17	Good combustion practices, non-emergency operation limited to 36 hrs/yr. See Permit conditions
			CH_4	No Emission Limit Established[4]		
			N_2O			

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[4]	No Emission Limit Established[6]	Implementation of good operational practices.
			CH_4	No Emission Limit Established[4]		
3PM18.044	3PM18.044	FRAC III Fire Water Pump	CO_2	14.96	15	Good combustion practices, non-emergency operation limited to 36 hrs/yr.
			CH_4	No Emission Limit Established[4]		
			N_2O			
Totals			**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 0.12TPY CO_2e.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions and FRAC III Miscellaneous emissions.