Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit
for Targa Gas Processing LLC, Longhorn Gas Plant

Permit Number: PSD-TX-106793-GHG

March 2013

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 February 23, 2012, Targa Gas Processing LLC (Targa) Longhorn Gas Plant (LGP) submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from proposed construction. EPA declared the application complete on September 11, 2012. Targa proposes to construct a new natural gas processing plant for deep ethane recovery. In connection with the LGP project, Targa submitted an application for an oil and gas production facilities non-rule standard permit for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on February 16, 2012.

After reviewing the application, EPA Region 6 has prepared the following Statement of Basis (SOB) and draft air permit to authorize the construction of air emissions sources at the proposed Targa LGP. 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 facility, the applicable air permit requirements, and an analysis showing how the applicant will comply with the requirements.

EPA Region 6 concludes that Targa LGP's application 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 requested by EPA and provided by Targa LGP, and EPA's own technical analysis. EPA is making all this information publicly available as part of the record for this permit action.

II. Applicant

Targa Gas Processing LLC – Longhorn Gas Plant
1000 Louisiana St., Ste. 4300
Houston, TX 77002

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

Contact:
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Targa Gas Processing LLP – Longhorn Gas Plant
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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 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:
Kyndall Cox
Air Permitting Section (6PD-R)
(214) 665-8567

The Non-GHG PSD Permitting Authority for the State of Texas is:

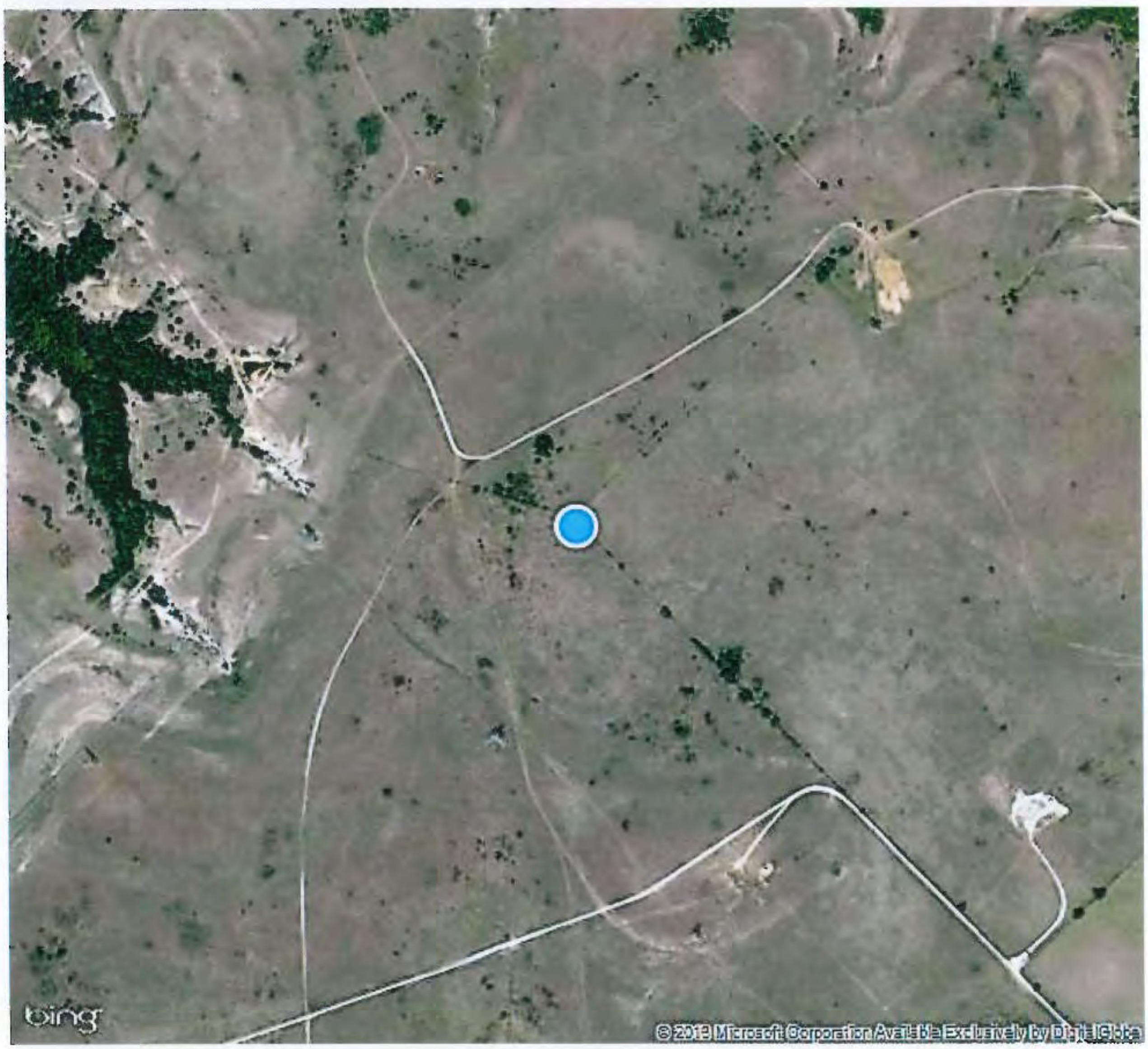
Air Permits Division (MC-163)
TCEQ
P.O. Box 13087
Austin, TX 78711-3087

IV. Facility Location

The Targa Gas Processing LLC Longhorn Gas Plant will be located in Wise County, Texas, and this area is currently designated "nonattainment" for Ozone. The nearest Class 1 area is the Wichita Mountains in Oklahoma, which are located more than 100 miles from the site. The geographic coordinates of the facility are as follows:

Latitude:	33° 18' 39"
Longitude:	-97° 31' 36"

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



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

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. EPA concludes Targa LGP's application is subject to PSD review for the pollutant GHGs, as described at 40 CFR § 52.21(b)(1) and (b)(49)(v). Under the project, the GHG emissions at the proposed new source are approximately 229,170 tons per year (tpy), which exceeds the applicability thresholds of 100,000 tpy CO_2e and 250 tpy on a GHG mass basis.

TCEQ, the permitting authority for regulated NSR pollutants other than GHGs, has issued a minor NSR permit that ensures emissions of all other pollutants will be below the significant emissions rates found at 40 CFR 52.21(b)(23). Specifically, TCEQ issued a non-rule standard permit for oil and gas production facilities, registration #106793, and the applicant therefore represents that no other regulated NSR pollutants are subject to PSD review.

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. The applicant has submitted an analysis to meet the requirements of 40 CFR § 52.21(o), as it may otherwise apply to the project.

VI. Project Description

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

After inlet separation and filtration, the inlet gas flows into the Amine Contactor, where the gas is contacted with an aqueous solution of UCARSOL AP-814 amine to remove CO_2. CO_2 exits with the amine from the bottom of the contactor and is heated and regenerated using closed hot oil system in the Amine Regenerator. Hot oil is circulated and supplied by the Heating Medium Heater (EPN 4). The CO_2 released from the regeneration process is routed to the onsite

Regenerative Thermal Oxidizer (RTO, EPN 5), where the vent gas is combusted and burned. When the RTO is down for maintenance the vent gas is routed to a flare (EPN 15). Treated gas (less CO_2) exits the Amine Contactor and is routed to the Treated Gas Coolers where it is cooled with ambient air. Any condensed water drops out in the Treated Gas Scrubber. Water that does not drop out is recycled back to the amine process for reuse.

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

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

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

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

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

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

VII. General Format of the BACT Analysis

The BACT analyses were conducted in accordance with EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (March 2011), which outlines the steps for conducting a top-down BACT analysis. Those steps 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

The majority of the contribution of GHGs associated with the project is from combustion sources (i.e., thermal oxidizer, glycol reboiler, hot oil heater, regenerant heater, and flares)[1]. The site has some fugitive emissions from piping components which contribute a minor amount of GHGs, estimated at 0.2% of the project's total CO_2e emissions of approximately 229,173 tpy. 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:

- Regenerative Thermal Oxidizer (EPN 5 and EPN 5-MSS)
- Glycol Reboiler (EPN 1), Molecular Sieve Regeneration (EPN 3) and Hot Oil (EPN 4) Heaters

[1] GHG emissions from the thermal oxidizer include both the CO_2 produced from combustion of VOC and CH_4, and the CO_2 contained in the waste gas that arrives from the amine regenerator.

- Flares (EPN6, EPN 6-MSS, EPN 15 and EPN 15-MSS)
- Pipeline Pig Receivers (EPN 7-MSS and EPN 8-MSS)
- Process Fugitives (EPN FUG-1)

IX. Regenerative Thermal Oxidizer (EPN 5) and RTO Start Up (EPN 5-MSS)

As part of the PSD review, Targa provides a 5-step top-down BACT analysis for the regenerative thermal oxidizer (RTO, EPN 5) in the GHG permit application. Targa's LGP will be equipped with one regenerative thermal oxidizer to control emissions from the waste streams of both the amine unit and glycol unit. EPA has reviewed Targa's BACT analysis for the RTO, which has been incorporated into this Statement of Basis, and also provides its own analysis in setting forth BACT for this proposed permit as summarized below.

Step 1 – Identification of Potentially Available Control Technologies

- *Carbon Capture and Sequestration (CCS)* – CCS is an available add-on control technology for many types of combustion units.
- *Highly Efficient Design* – Efficient RTO design includes flow measurement and monitoring/control of waste gas heating values, both of which can improve the destruction efficiency of VOCs and CH_4 entrained in the waste streams.
- *Low Carbon Fuel Selection* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input.
- *Good Combustion, Operating and Maintenance Practices* – The formation of GHGs can be controlled by proper operation and using good combustion techniques.

Carbon Capture and Sequestration (CCS)

Carbon capture and storage is an available GHG control technology for "facilities emitting CO_2 in large amounts, 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.

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[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).

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 facility; the third approach, post-combustion capture, is available to Targa's RTO, reboiler and heaters.

With respect to post-combustion capture, a number of methods may potentially be used for separating the CO_2 from the exhaust gas stream, including adsorption, physical absorption, chemical absorption, cryogenic separation, and membrane separation (Wang et al., 2011). Many of these methods are either still in development or are not suitable for treating power plant flue gas due to the characteristics of the exhaust stream (Wang, 2011; IPCC, 2005). Of the potentially applicable technologies, post-combustion capture with an amine solvent such as monoethanolamine (MEA) is currently the preferred option because it is the most mature and well-documented technology (Kvamsdal et al., 2011), and because it offers high capture efficiency, high selectivity, and the lowest energy use compared to the other existing processes (IPCC, 2005). Post-combustion capture using MEA is also the only process known to have been previously demonstrated in practice on gas turbines (Reddy, Scherffius, Freguia, & Roberts, 2003).

In a typical MEA absorption process, the flue gas is cooled before it is contacted counter-currently with the lean solvent in a reactor vessel. The scrubbed flue gas is cleaned of solvent and vented to the atmosphere while the rich solvent is sent to a separate stripper where it is regenerated at elevated temperatures and then returned to the absorber for re-use. Fluor's Econamine FG Plus process operates in this manner, and it uses an MEA-based solvent that has been specially designed to recover CO_2 from oxygen-containing streams with low CO_2 concentrations typical of gas turbine exhaust (Fluor, 2009). This process has been used successfully to capture 365 tons per day of CO_2 from the exhaust of a natural gas combined-cycle plant owned by Florida Power and Light in Bellingham, Massachusetts. The CO_2 capture plant was maintained in continuous operation from 1991 to 2005 (Reddy, Scherffius, Freguia, & Roberts, 2003).

Once CO_2 is captured from the flue gas, the captured 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]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project.[4]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- CO_2 capture and storage (up to 90%)
- Highly Efficient design (up to 15%)
- Good combustion, operation, maintenance practices (up to 10%)
- Use of low carbon fuels (unquantifiable due to intermittent fuel use)

Virtually all GHG emissions result from the combustion of stripped amine gas in the RTO. CO_2 capture and storage is capable of achieving up to 90% reduction of CO_2 emissions and is considered the most effective control method. RTO design specifications can produce improvements in efficiency up to 15%. Good work practices (e.g., good combustion, operation and maintenance practices) and using low carbon fuels during start up can both minimize GHG emissions from fuel combustion.

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 Sequestration

Targa developed a cost analysis for CCS that provided the basis for eliminating the technology as a feasible control option in this step of the BACT process based on economic costs, logistical viability, and environmental impacts. The recovery and purification of CO_2 from the amine unit would necessitate additional processing with energy and environmental tradeoffs to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment to separate, capture, compress, and transfer the CO_2 stream would require extra energy and generate additional air emissions, both criteria and GHG pollutants.

[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

[4] Based on the information provided by Targa and reviewed by EPA for this BACT analysis, while there are some portions of CCS that may be technically infeasible for this project, EPA has determined that overall Carbon Capture and Sequestration (CCS) technology is technologically feasible at this source.

Targa's assessment also included an analysis of the feasibility of transferring the CO_2 to an active injection well in or around Wise County, Texas. The Texas Railroad Commission (RRC) website[5] provides details on registered wells and permitted fluids for injection. Targa identified the nearest CO_2 injection well to the proposed facility to be 110 miles away. However, the direct path to access the pipeline would have to be laid through the Dallas-Fort Worth metroplex, which is technically, economically and environmentally improbable. Targa used the 110 mile pipeline length as a conservative length and 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. The total pipeline annualized cost for CCS over the 10 year expected life of the equipment is approximately \$11, 276,000 per year[7] and the annualized project cost over twenty years without CCS is \$13,473,000 per year. The annualized costs for CCS would effectively double the project cost. EPA Region 6 reviewed Targa's CCS cost estimate and believes it adequately demonstrates that the costs associated with a CCS control for this project are excessive in relation to the overall cost of the project without CCS.

<u>Highly Efficient design</u>

Targa has proposed an RTO with a thermal heat exchanger efficiency of 95% that can self-sustain the normal operating temperature with a waste gas heat input as low as 8-10 Btu/scf. Supplemental natural gas will not be needed to maintain proper temperature in the RTO.

<u>Good combustion, operation, and maintenance practices</u>

Good combustion practices for the RTO include monitoring and analysis of waste gas flow rate, monitoring temperature in the combustion chamber, and periodic maintenance.

<u>Low carbon fuel selection</u>

Natural gas is the lowest carbon fuel available for use in the proposed RTO. Natural gas is a clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Step 5 – Selection of BACT

The following BACT practices are proposed for the RTO:

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5 http://www.rrc.state.tx.us/data/online/gis/index.php

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 See the CCS cost analysis in Appendix E of the permit application.

- *Highly Efficient design* – Targa LGP will be utilizing a regenerative thermal oxidizer with 99% DRE for methane (CH_4). The RTO has 95% thermal efficiency and can maintain proper combustion temperature from the waste gas without additional natural gas combustion.
- *Good combustion, operation, and maintenance practices* – Periodic maintenance will help preserve the efficiency of the RTO. Temperature and flow rate monitoring will ensure proper operation of the RTO.
- *Use of low carbon fuels (during start up)* – Targa shall combust pipeline quality natural gas during RTO start up.

Use of these practices corresponds with a permit limit of 167,897 tpy CO_2e for the RTO.

X. Glycol Reboiler (EPN 1), Molecular Sieve Regeneration (EPN 3) and Hot Oil Heaters (EPN 4)

Targa's LGP facility has one triethylene glycol (TEG) reboiler, one molecular sieve regeneration heater and one hot oil heater (EPNs 1, 3, and 4 respectively). The hot oil heater (EPN 4) provides heat to the amine regenerator's closed loop system and has a maximum rated capacity of 98 MMBtu/hr. The TEG is regenerated in a 2.0 MMBtu/hr direct fired reboiler (EPN 1). Heat needed for the dehydration system is provided by the regeneration heater (EPN 3) with a maximum rated capacity of 12 MMBtu/hr.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Carbon Capture Sequestration (CCS)* – CCS is an available add-on control technology that is applicable for heaters, reboilers and RTO.
- *Low Carbon Fuel Selection* – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input.
- *Good Combustion, Operating and Maintenance Practices* – The formation of GHGs can be controlled by proper operation and using good combustion techniques.
- *Oxygen Trim Controls* – Monitors for oxygen and intake flow can help to optimize combustion efficiency, as excess air in the combustion chamber may lead to inefficient combustion and increased emissions.
- *Fuel Gas Pre-heater / Air Pre-heater* – Preheating the fuel stream reduces the heating load, increases the thermal efficiency, thereby reducing emissions.
- *Efficient Heater Design* – Good heater design to maximize thermal efficiency.
- *Periodic Tune-up* – Periodically tune-up heaters to maintain optimal thermal efficiency.

Step 2 – Elimination of Technically Infeasible Alternatives

All options listed in Step 1 are considered technically feasible, except for fuel gas preheating and CCS. Preheating the fuel gas is not feasible due to the size of the proposed heaters (<100 MMBtu/hr). CCS is also being eliminated based on the previous discussion in Section IX.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Low Carbon Fuels (28%),
- Heater design (up to 10%),
- Periodic tune-up (1-10%),
- Oxygen trim controls (1-3%),
- Good combustion, operating and maintenance practices (not quantifiable).

Fuels used in industrial process and power generation are typically coal, fuel oil, natural gas, and process fuel gas. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Good heater design, oxygen trim control, periodic tune-ups, and good operating practices 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 most recent ENERGY STAR guide (2008)[8], which addressed improvements to existing energy systems as well as new equipment.

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

Low carbon fuel selection

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.

Heater Design

New heaters can be designed with efficient burners, increased 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.

[8] Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)

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 over time to age.

Oxygen Trim 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.

Good Combustion Practices

Good combustion practices for the heaters include:
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.

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	Control Device	BACT Emission Limit / Requirements	Year Issued	Reference
Energy Transfer Company, Jackson County Gas Plant Ganado, TX	Gas Processing Plant	Energy Efficiency/ Good Design & Combustion Practices	GHG BACT 1,102.5 lbs CO_2/MMSCF natural gas output for each plant. 1 plant contains: hot oil heater (48.5 MMBtu/hr); Trim Heater (17.4 MMBtu/hr); Molecular Sieve Regeneration Heater (9.7 MMBtu/hr); and TEG Dehydrator Unit Regeneration Gas Heater (3 MMBtu/hr).	2012	PSD-TX-1264-GHG

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. Targa LGP will utilize a burner management system on the heaters, such that intelligent flame ignition, flame intensity controls, and flue gas recirculation to 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.
- *Oxygen trim controls* – Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture and limit excess air to 15%.
- *Low carbon fuel usage* – LGP will be firing only pipeline quality natural gas, which results in 28% less CO_2 production than fuel oils.
- *Good Combustion Practices* – Good combustion techniques include: tuning the system to the best air-to-fuel ratio, residence time, temperature, and combustion zone turbulence to enable the lowest GHG emissions.

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

Using the BACT practices above will result in an output based BACT limit for the boiler and heaters based on millions standard cubic feet per day (MMSCFD) of natural gas liquids processed.

The Glycol Reboiler (EPN 1), Regeneration Heater (EPN 3) and Hot Oil Heater (EPN 4) shall have a 1,783.23 lbs CO_2/MMSCFD processed BACT limit. Targa's proposed hot oil heater has almost double the heating capacity of the similar unit at Energy Transfer Company. The gas entering the Longhorn Gas Plant will have a high CO_2 inlet concentration (with little H_2S) so a larger hot oil heater is needed for regeneration than at a similar plant with less CO_2 in the inlet gas. The larger hot oil heater with a higher heat capacity will mean more fuel will be combusted. However, as detailed above, Targa will employ similarly energy efficient and good combustion practices. Compliance with the emissions limit will be determined on a 365-day rolling average.

Both the hot oil and regenerant 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. Targa LGP will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters.

Targa LGP 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-1. The equation for estimating CO_2 emissions as specified in 40 CFR 98.33(a)(2)(i) is as follows:

$$CO_2 = 1x10^{-3} * Fuel * HHV * EF * 1.102311$$

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).
HHV = Annual average high heat value of the gaseous fuel (MMBtu/scf). The average HHV shall be calculated according to the requirements at §98.33(a)(2)(ii).
EF = Fuel-specific default CO_2 emission factor, from Table C-1 of this subpart (kg CO_2/MMBtu).
$1x10^{-3}$ = Conversion of kg to metric tons.
1.102311 = Conversion of metric tons to short tons.

XI. Flares (EPN 6, EPN 6-MSS, EPN 15, and EPN 15-MSS)

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

Step 1 – Identification of Potential Control Technologies for GHGs

- *Low Carbon Fuel Selection* – Use of natural gas, which represents the available pilot fuel type with the lowest carbon intensity on heat input basis.
- *Flare Gas Recovery* – A flare gas recovery compressor system can be used to recover flared gas to the fuel gas system.
- *Good Combustion, Operating and Maintenance Practices* – Good combustion practices improve flare efficiency and include proper orientation, maintenance, and tune-up of the flare at least annually.
- *Good Flare Design* – Good flare design can be employed to destroy large fractions of the flare gas. Manufactures of flares and flare tips have worked to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, blower controls, and monitoring/control of waste gas heating value.
- *Limited Vent Gas Release to Flare* – Minimizing the number and duration of MSS activities and therefore limiting vent gases routed to the flare to help reduce emissions due to MSS activities.

Step 2 – Elimination of Technically Infeasible Alternatives

All options in Step 1 are considered technically feasible except flare gas recovery. Neither flare will be a process flare, but used intermittently for MSS activities. Without a continuous stream being combusted other than pilot gas, flare gas recovery would be infeasible to implement.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Low Carbon Fuels (28%),
- Good Flare Design (1 – 15%),
- Good Combustion, Operation & Maintenance Practices (1 – 10 %)
- Flare Minimization (unquantifiable)

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

There are no negative environmental impacts associated with any proposed control options. Fuel selection, flare minimization, proper design, and good operation and combustion practices for the flare are all potentially equally effective. Further evaluation is unnecessary because each of these technologies is being proposed for use at the project.

Step 5 – Selection of BACT

Targa proposes to use all of the above-stated control technologies to minimize GHG emissions from flaring at the proposed facility. The following specific BACT practices are proposed for the flares:

- *Fuel Selection* – Targa LGP will utilize pipeline quality natural gas in the pilots of the flare.
- *Flare Design* – The flare shall be designed and operated in accordance with 40 CFR 60.18 including specifications of minimum heating value of the waste gas, maximum tip velocity and pilot flame monitoring.
- *Good Combustion Practices* – The formation of GHGs can be controlled by proper operation and using good combustion practices. Poor flare combustion efficiencies lead to higher methane emissions and higher overall GHG emissions. Targa LGP will monitor the waste gas composition monthly, and will have air assisted combustion allowing for improved flare gas combustion control and minimizing periods of poor combustion. Periodic maintenance will help maintain the efficiency of the flare.
- *Flare Minimization* – Targa proposes to limit MSS activities and flaring events to minimize GHG emissions from this source.

Use of these practices corresponds with a permit limit during normal operations of 269 tpy CO_2e for the EPN 6 flare and a limit of 80 tpy CO_2e for the EPN 15 flare. Flare emissions from scheduled maintenance, startup and shutdown (MSS) activities represent approximately 1% of total CO_2e emissions from the Targa LGP facility. The Agency is requiring through maintenance and work practices limits on the number and duration of MSS events. MSS emissions for EPN 6-MSS shall be limited to 10 tpy CO2e and not more than nine events each per year for blowdowns of the residue and refrigerant compressors, and fifty-two (52) one-hour pigging events per year. For EPN 15-MSS, MSS emissions shall be limited to 2,911 tpy CO2e and not more than 124 hours per year. To demonstrate compliance with the MSS emissions, Targa LGP shall record the time, date, fuel heat input (HHV) in MMBTU/hr and duration of each startup and shutdown event. Records of all emission limit calculations and startup/shutdown events shall be kept on-site for a period of five (5) years.

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

Natural gas will flow into the plant from either of two delivery points through high pressure pipelines equipped with onsite pipeline pig receivers (EPN 7-MSS, EPN 8-MSS). Gas from the pig receivers flows into the inlet slug catcher for liquid removal. Methane emissions from pipeline pigging events has been estimated to be 3.8 tpy as CO_2e. Emissions from the pig receivers account for a very small percentage (>> 0.01%) of the project's total CO_2e emissions of 229,173 tpy.

Step 1 – Identification of Potential Control Technologies for GHGs

The only identified control technology for CO_2e emissions from the pig receivers is to limit the number of pigging events.

Step 2 – Elimination of Technically Infeasible Alternatives

No other alternatives identified.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Not applicable.

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

Limiting the number of pipeline pigging events will minimize emissions from pig receivers.

Step 5 – Selection of BACT

The Agency is requiring through maintenance and work practices limits on the number of pipeline pigging events. EPN 7-MSS and EPN-8MSS shall not have more than twenty-four (24) events per year for pigging.

XIII. Process Fugitives (EPN FUG-1)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane. The additional methane emissions from process fugitives have been conservatively estimated to be 401 tpy as CO_2e. Fugitive emissions of methane are negligible, and account for a very small portion (approximately 0.2%) of the project's total CO_2e emissions.

Step 1 – Identification of Potential Control Technologies for GHGs

The only identified control technology for CO_2e process fugitive emissions is use of a leak detection and repair (LDAR) program. LDAR programs vary in stringency as needed for control of VOC emissions; however, due to the negligible amount of GHG emissions from fugitives, LDAR programs would not be considered for control of GHG emissions alone. As such, evaluating the relative effectiveness of different LDAR programs is not warranted.

Step 2 – Elimination of Technically Infeasible Alternatives

LDAR programs are a technically feasible option for controlling process fugitive GHG emissions.

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, with Consideration of Economic, Energy, and Environmental Impacts

While technically feasible, use of an LDAR program to control the small amount of GHG emissions that occur as process fugitives is potentially costly. However, TCEQ is requiring 28 VHP in Targa's non-GHG minor NSR permit for purposes of controlling VOC, which will also result in effective control of the small amount of GHG emissions from the same piping components. Therefore, Targa proposes to implement TCEQ's 28VHP LDAR program[9] at the Longhorn Gas Plant to minimize process fugitive emissions at the plant.

Step 5 – Selection of BACT

EPA concurs with Targa's assessment that using the TCEQ 28LAER LDAR program is an appropriate control of GHG emissions. Targa also identified and proposed the use of air-driven pneumatic controllers as BACT for fugitives as well as audio/visual/olfactory monitoring between instrumented checks and tandem seals equipped with alarms to alert personnel when the first seal begins to leak. EPA determines that the TCEQ 28VHP work practice standard for fugitives for control of CH_4 emissions is BACT. A numerical limit for control of these GHG emissions is not proposed.

[9] The boilerplate special conditions for the TCEQ 28VHP LDAR program can be found at http://www.tceq.state.tx.us/assets/public/permitting/air/Guidance/NewSourceReview/bpc_rev28vhp.pdf. These conditions are included in the TCEQ issued NSR permit.

XIV. 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 adopted by EPA. Further, EPA designated Targa Gas Processing LLC ("Targa") and its consultant, Raven Environmental Services, Inc. ("Raven"), as non-federal representatives for purposes of preparation of the BA.

A draft BA has identified five (5) species listed as federally endangered or threatened in Wise County, Texas:

Federally Listed Species for Harris County by the U.S. Fish and Wildlife Service (USFWS) and the Texas Parks and Wildlife Department (TPWD)	Scientific Name
Birds	
Black-capped Vireo	*Vireo atricapilla*
Whooping Crane	*Grus americana*
Interior Least Tern	*Sterna antillarum*
Mammals	
Gray Wolf	*Canis lupus*
Red Wolf	*Canis rufus*

Based on the information provided in the BA and following discussions with USFWS, EPA concludes that the proposed PSD permit allowing Targa to construct a new natural gas processing plant will have no effect on the 5 species indicated above because 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 is necessary. 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 at http://yosemite.epa.gov/r6/Apermit.nsf/AirP.

XV. National Historic Preservation Act (NHPA)

Section 106 of the NHPA requires EPA to consider the effects of this permit action on properties eligible for inclusion in the National Register of Historic Places. To make this determination, EPA relied on a cultural resource report prepared by Deep East Texas Archaeological Consultants ("DETAC") on behalf of Raven submitted on March 22, 2012.

For purposes of the NHPA review, the Area of Potential Effect (APE) was determined to be approximately 58 acres of land that includes the construction footprint of the new facility and a new access road approximately 1.8 miles long leading to the facility. DETAC conducted a field survey of the property and a desktop review on the archaeological background and historical records within a 1-mile radius area of potential effect (APE) which included a review of the Texas Historical Commission's online Texas Archaeological Site Atlas (TASA) and the National Park Service's National Register of Historic Places (NRHP). Based on the desktop review, three previous cultural surveys were made within a 1-mile radius of the APE. Five historic or archaeological sites were identified from those reports, all of which are outside of the APE.

Based on the results of the field survey within the APE, that included 82 shovel tests, no archaeological resources were found. However, a historic windmill and water trough were identified near the mid-point of the proposed project site. The report indicates that the windmill is most likely an Aeromotor 602, which was manufactured between 1916 and 1933. Steel water troughs were first manufactured in 1904 and the self-oiling enclosed gear cases for windmills were first manufactured in 1915. A search of the NRHP database revealed that freestanding windmills listed on the NRHP have unique architectural elements or were an integral part of a NRHP site, e.g., a windmill used to power a sugar mill or provide water to a house. The windmill found during the survey is most likely associated with another historic site east of the project area (which was not considered eligible for listing on the NRHP), and not an architectural element of that site because it was used for watering livestock instead of supplying the house with water. The windmill found during the survey is not eligible for inclusion to the NRHP because: 1) it is not a unique architectural design, 2) this style of windmill is still in service, and 3) the windmill is free standing farm equipment not providing water or power to an archaeological site.

EPA Region 6 determines issuance of the permit to Targa will not affect properties on or potentially eligible for listing on the National Register. Although there is a historic structure within the APE, it is not eligible for listing on the NRHP properties, and a potential for the location of archaeological resources is low within the construction footprint itself.

On June 11, 2012, 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.

XVI. Environmental Justice (EJ)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch 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)]. This permitting action, if finalized, authorizes emissions of GHG, controlled by what we have determined is the Best Available Control Technology for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no National Ambient Air Quality Standard (NAAQS) for GHGs. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are 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 [PSD and Title V Permitting Guidance for GHGs at 48]. 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.

XVII. Conclusion and Proposed Action

Based on the information supplied by Targa, our review of the analyses contained in the TCEQ PSD Permit Application and the GHG 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 Targa a PSD permit for GHGs for the Longhorn Gas Processing (LGP) facility, subject to the PSD 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 Emission Limits

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

Table 1. Facility Emission Limits[1]

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
1	1	TEG-1 Glycol Reboiler	CO_2	1,024	1,024	1,783.23 CO2 lb/MMSCF (combined limit for the three units) on 365- day rolling. See permit condition III.B.2.
			CH_4	0.02		
			N_2O	No Numerical Limit Established[4]		
3	3	HTR-1 Mol. Sieve Regen Heater	CO_2	6,349	6,355	
			CH_4	0.13		
			N_2O	0.01		
4	4	HTR-2 Hot Oil Heater	CO_2	50,174	50,222	
			CH_4	0.94		
			N_2O	0.09		
2,15	5	RTO-1 Regen Thermal Oxidizer	CO_2	167,739	167,897	Good combustion practices and annual compliance testing. See permit condition III.A.1.
			CH_4	1.48		
			N_2O	0.41		
5-MSS	5-MSS	RTO-1 Startup	CO_2	1.40	1.40	
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
6	6	Flare 1	CO_2	269	269	Good combustion practices and annual compliance testing. See permit condition III.C.1
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		
6	6-MSS	Flare 1 MSS	CO_2	10	10	
			CH_4	No Numerical Limit Established[4]		
			N_2O	No Numerical Limit Established[4]		

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

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling average basis.
2. The TPY emission limits specified in this table are not to be exceeded for this facility and include emissions from the facility during all operations and include MSS activities.
3. Global Warming Potentials (GWP): $CH_4 = 21$, $N_2O = 310$
4. All values indicated as "No Numerical Limit Established" are less than 0.01 TPY with appropriate rounding.
5. Pipeline pigging emissions (7-MSS and 8-MSS) are estimated to be 0.18 TPY of CH_4 and 3.8 TPY CO_2e.
6. Fugitive process emissions (FUG-1) are estimated to be 1.5 TYP of CO_2, 19 TPY of CH_4 and 401 TPY CO_2e. In lieu of an emission limit, the emissions will be limited by implementing a design/work practice standard as specified in the permit.
7. The total emissions for CH_4 and CO_2e include the PTE for process fugitive emissions of CH_4. These totals are given for informational purposes only and do not constitute emission limits.