Statement of Basis

Draft Greenhouse Gas Prevention of Significant Deterioration Preconstruction Permit for the Enterprise Products Operating LLC, Mont Belvieu Complex

Permit Number: PSD-TX-1286-GHG

August 2012

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 December 21, 2011, the Enterprise Products Operating LLC (Enterprise) Mont Belvieu Complex, submitted to EPA Region 6 a Prevention of Significant Deterioration (PSD) permit application for Greenhouse Gas (GHG) emissions from a proposed modification project. On May 16, 2012 Enterprise submitted a revised application. In connection with the same proposed modification project, Enterprise submitted a PSD permit application for non-GHG pollutants to the Texas Commission on Environmental Quality (TCEQ) on December 19, 2011. The project at the Mont Belvieu Complex proposes to construct two new natural gas liquids (NGL) fractionation (Eagleford Fractionation) units to separate a NGL feed into separate ethane, propane, butane, and gasoline fractions. Enterprise also proposes to construct a deisobutanizer (DIB) unit to separate isobutene and normal butane from mixed butane streams. 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 Enterprise, Mont Belvieu Complex.

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 complied with the requirements.

EPA Region 6 concludes that Enterprise'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 requested by EPA and provided by Enterprise, and EPA's own technical analysis. EPA is making all this information available as part of the public record.

II. Applicant

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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 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:
Aimee Wilson
Air Permitting Section (6PD-R)
(214) 665-7596

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

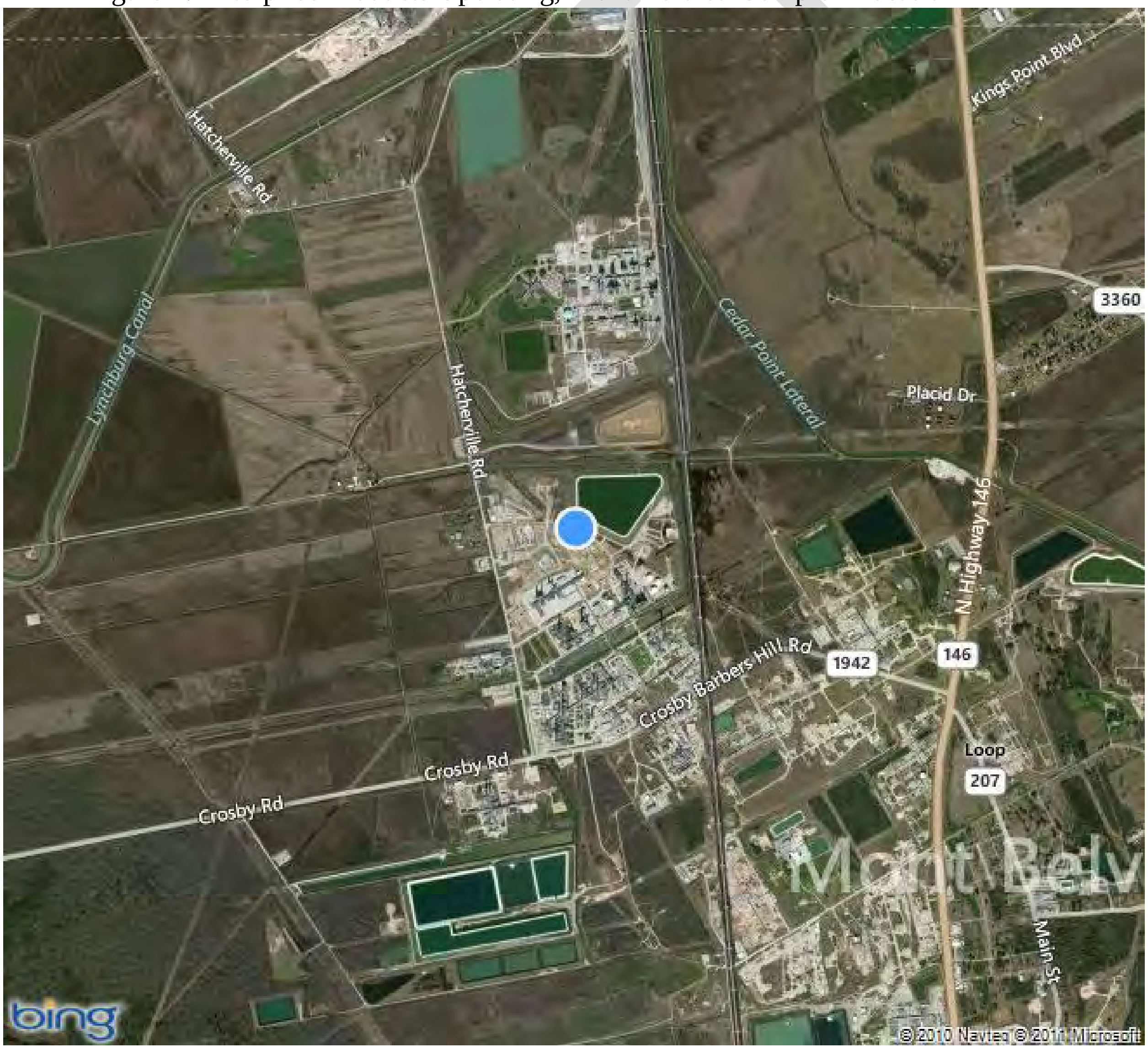
IV. Facility Location

The Enterprise, 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 Big Bend National Park, which is located well over 100 miles from the site. The geographic coordinates for this facility are as follows:

Latitude: 29º 51’ 53” North
Longitude: -94º 54’57” West

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

Figure 1. Enterprise Products Operating, Mont Belvieu Complex Location



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

EPA concludes Enterprise'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)(23) and (49)(iv). Under the project, GHG emissions are calculated to increase over zero tpy on a mass basis and to exceed the applicability threshold of 75,000 tpy CO_2e (Enterprise calculates CO_2e emissions of 238,425 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 proposed project is subject to PSD review for non-GHG pollutants. TCEQ has determined that the proposed project is subject to NNSR review for Volatile Organic Compounds (VOC) and subject to PSD for Carbon Monoxide (CO). At this time, TCEQ has not issued the NNSR or PSD permit for the non-GHG pollutants.

Accordingly, under the circumstances of this project, the TCEQ will issue the non-GHG portion of the PSD permit and EPA will issue the GHG portion.[1]

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 neither required the applicant to model or conduct ambient monitoring for GHGs, nor have we 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. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from TCEQ.

VI. Project Description

The proposed GHG PSD permit, if finalized, will allow Enterprise to construct two new NGL fractionation units (Eagleford Fractionation) consisting of two fractionation unit deethanizer distillation columns, two fractionation unit debutanizer distillation columns, two hot oil heaters, two regenerant gas heaters, a flare, and a DIB unit. The DIB unit will consist of a deisobutanizer distillation column, and share a flare with the Eagleford Fractionation units at the existing oil and gas production facility at the Mont Belvieu Complex located in Mont Belvieu, Chamber County, Texas. Each fractionation unit will have a nominal feed capacity of 110,000 barrels per day. The

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[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

GHG emissions will be generated by the two hot oil heaters, the two regenerant heaters, and the flare. All other new units at the facility are either a closed system, have only fugitive emissions, or vent to the flare.

The pipeline feed mixtures is processed in the feed filter, feed coalesce, and amine contactors to remove particulates, sulfides, and carbon dioxide. The sweetened feed is then dehydrated and fed to the Deethanizer column. The Deethanizer is used to fractionate the feed into two fractions. The overhead vapor fraction consists of ethane and lighter components and is condensed by heat exchange against propylene refrigerant. A portion of the condensed ethane is pumped out of the unit as ethane product to the existing storage facility, and the balance is refluxed back to the column. The bottom fraction from the column, consisting mainly of propane and heavier components, is fed to the Depropanizer column. Heat for fractionation is provided by a hot oil reboiler at the bottom of the column.

The Depropanizer column take the feed from the Deethanizer bottom and separates it into a propane and lighter fraction, which goes overhead, and a butane and heavier fraction, which exits the bottom. Part of the propane is refluxed back to the column and the balance is sent to the existing storage complex as product. Heat for fractionation is provided by a hot oil reboiler at the bottom of the column.

The stream from the bottom of the Depropanizer is fed to the Debutanizer column, which fractionates it into an overhead stream containing mixed butanes (primarily normal butane and isobutene), and a bottoms gasoline stream which contains pentanes and heavier. Part of the overhead butane stream is refluxed back to the column and the balance is sent to storage tanks as an intermediate feed for other units or as commercial butane product. The bottoms gasoline is routed to existing gasoline treating facilities. Heat for fractionation in the Debutanizer is provided by a hot oil reboiler at the bottom of the column.

The mixed butanes are routed to the deisobutanizer distillation column, where the separation of isobutene and normal butane occurs. The overhead vapor stream from the column is isobutene, which is compressed into liquid phase isobutene. The liquefied isobutene product is split into two streams, one providing reflux for the column, and the remaining stream sent to the storage area or delivered to other Enterprise units as feed material. The overhead compressors are electric driven and do not have any combustion emissions.

Hot oil used in the column reboilers is provided by a natural gas fired hot oil system (EPNs HR15.001A and HR15.001B). The same hot oil heater also supplies heat for the amine regeneration column used to sweeten the NGL entering the unit. The heat needed for the dehydration system is provided by the regenerant gas heater (EPNs 15.002A and 15.002B).

VII. General Format of the BACT Analysis

The BACT analyses was conducted in accordance with the *"Top-Down" Best Available Control Technology Guidance Document* outlined in the 1990 draft U.S. EPA *New Source Review Workshop Manual*, 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.

Also in accordance with the top-down BACT guidance, the BACT analyses also take into account the energy, environmental, and economic impacts of the control options during step 4. Emission reductions may be determined through the application of available control techniques, process design, and/or operational limitations. Such reductions are necessary to demonstrate that the emissions remaining after application of BACT will not cause adverse environmental effects to public health and the environment.

Each of the emission unit submitted in the PSD GHG application was evaluated separately in the top-down 5-step BACT analysis.

VIII. Applicable Emission Units and BACT Discussion

The majority of the contribution of GHGs associated with the project is from emissions at combustion sources (i.e., hot oil heaters, regenerant heaters, and flare). The site has some fugitive emissions from piping components which contribute an insignificant amount of GHGs. Fugitive emissions account for 22 TPY of CO_2e, or less than 0.01% of the project's total CO_2e emissions. 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:

- Hot Oil (HR15.001A and HR15.001B) and Regenerant (HR15.002A and HR15.002B) Heaters
- Flare (SK25.001)
- Fugitives (FRAC F EFa and FRAC F EFb)

IX. Hot Oil (HR15.001A and HR15.001B) and Regenerant Heaters (HR15.002A and HR15.002B)

The fractionation unit has two hot oil heaters (HR15.001A and HR15.001B) and two regenerant heaters (HR15.002A and HR15.002B). The hot oil heaters provide hot oil used in the column reboilers and the amine regeneration column. The hot oil heaters have a maximum rated capacity of 140 MMBtu/hr, however the hot oil heaters may fire at 160 MMBtu/hr on an instantaneous basis, not to exceed 1 hour. Heat needed for the dehydration system is provided by the regenerant gas heaters.

As part of the PSD review, Enterprise provides in the GHG permit application a 5-step top-down BACT analysis for the four heaters. EPA has reviewed Enterprise's BACT analysis for the heaters, 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 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.
- *Periodic Tune-up* – Periodically tune-up the heaters to maintain optimal thermal efficiency.
- *Heater Design* – Good heater design to maximize thermal efficiency.
- *Heater Air/Fuel Control* – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- *Waste Heat Recovery* – Use of heat recovery from both the heater exhausts and process streams to preheat combustion air, feed (oil) to heaters, or to produce steam for use at the site.
- *Product Heat Recovery* – Use of heat exchangers throughout the plant to recover usable heat from product streams reduces overall energy consumption and a reduction in the amount of fuel required by the heaters.
- *Use of Low Carbon Fuels* – 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.

Carbon Capture and Sequestration (CCS)

Carbon capture and storage is a GHG control process that can be used by "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] For purposes of a BACT analysis, CCS is classified as an add-on pollution control technology. The nascent technology of CCS involves the separation and capture of CO_2 from the combustion process flue gas, pressurization of the captured CO_2, and transportation by pipeline or other means of transportation, if necessary, to a site where it is injected into a long-term geological location. Several technologies are in various stages of development and are being considered for CO_2 separation and capture.

As it stands currently, CCS Technology and its components can be summarized in the table[3] below adopted from IPCC's *Carbon Dioxide Capture and Storage* report:

CCS Component	CCS Technology
Capture	Post-combustion
	Pre-combustion
	Oxyfuel combustion
	Industrial separation (natural gas processing, ammonia production)
Transportation	Pipeline
	Shipping
Geological Storage	Enhanced Oil Recovery (EOR)
	Gas or oil fields
	Saline formations
	Enhanced Coal Bed Methane Recovery (ECBM)
Ocean Storage	Direct injection (dissolution type)
	Direct injection (lake type)
Mineral carbonation	Natural silicate minerals
	Waste minerals
CO_2 Utilization/Application	Industrial Uses of CO_2 (e.g. carbonated products)

For large, point sources, there are three types of capture configurations – pre-combustion capture, post-combustion capture, and oxy-combustion capture:

[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] Intergovernmental Panel on Climate Change (IPCC) Special Report, Bert Metz, Ogunlade Davidson, Heleen de Coninck, Manuela Loos and Leo Meyer (Eds.), *Carbon Dioxide Capture and Storage* (New York: Cambridge University Press, 2005), Table SPM.2, 8. <http://www.ipcc.ch/pdf/special-reports/srccs/srccs_wholereport.pdf>

1) Pre-combustion capture implies as named, the capture of CO_2 prior to combustion. It is a technological option available to integrated coal gasification combined cycle (IGCC) plants. In these plants, coal is gasified to form synthesis gas (syngas with key components of carbon monoxide and hydrogen). CO is reacted with steam to form CO_2 which is then removed and the hydrogen is then diluted with nitrogen and fed into the gas turbine combined cycle.

2) Post-combustion capture involves extracting CO_2 in a purified form from the flue gas following combustion of the fuel. Primarily for coal-fired power plants and electric generating units (EGU), other industries can benefit. Currently, all commercial post-combustion capture is via chemical absorption process using monoethanolamine (MEA)-based solvents.[4]

3) Oxy-combustion technology is primarily applied to coal-burning power plants where the capture of CO_2 is obtained from a pulverized coal oxy-fuel combustion in which fossil fuels are burned in a mixture of recirculated flue gas and oxygen, rather than in air. The remainder of the flue gas, that is not recirculated, is rich in carbon dioxide and water vapor, which is treated by condensation of the water vapor to capture the CO_2.[5] In nearly all existing coal-burning power plants, nitrogen is a major component of flue gas in the boiler units that burn coal in air, post-combustion capture of CO_2 is essentially a nitrogen-carbon dioxide separation which can be done but at a high cost. However if there were no nitrogen present as in the case of oxy-combustion, then CO_2 capture from flue gas would be greatly simplified[6]. It is implied that an optimized oxy-combustion power plant will have ultra-low CO_2 emissions as a result.

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) into a storage area, in most cases, a geological storage area. It is also possible that CO_2 can be stored and shipped via all different modes of transportation via land, air and sea.

Geological storage of CO_2 involves the injection of compressed CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping, there are five types of geologic formations that are considered: clastic formations; carbonate formations; deep, unmineable coal seams; organic-rich

[4] Wes Hermann et al. *An Assessment of Carbon Capture Technology and Research Opportunities - GCEP Energy Assessment Analysis, Spring 2005*. <http://gcep.stanford.edu/pdfs/assessments/carbon_capture_assessment.pdf>
[5] U.S. Department of Energy, Office of Fossil Energy, National Energy Technology Laboratory, "Oxy-Fuel Combustion", August 2008. < http://www.netl.doe.gov/publications/factsheets/rd/R&D127.pdf>
[6] Herzog et al., page 4-5

shales; and basalt interflow zones. 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.[7]

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible for this project, except for waste heat recovery. The hot oil heaters, although of a size sufficient enough to consider use of waste heat recovery, are designed to maximize heat transfer to the oil medium, which results in a low exhaust gas temperature (393 ^{o}F) that does not contain sufficient residual heat to allow effective heat recovery. Use of flue gas heat recovery to preheat the heater combustion air is typically only considered feasible if the exhaust gas temperature is higher than 650 ^{o}F.[8] Moreover, the regenerant heaters cannot be used effectively for waste heat recovery, as they are on/off cycled heaters (design is firing about 8 hours and shutdown for 24 to 30 hours). For these reasons, use of waste heat recovery on the heaters was eliminated from further consideration.

Based on the information reviewed for this BACT analysis, while there are some portions of CCS that are technically infeasible for this project, EPA has determined that overall Carbon Capture and Storage (CCS) technology are technologically feasible at this source. Listed below is a summary of those CCS components that are technically feasible and those CCS components that are not technically feasible for Enterprise.

Step Two Summary for CCS for Enterprise

CCS Component	CCS Technology	Technical Feasibility
Capture	Post-combustion	Y
	Pre-combustion	N
	Oxyfuel combustion	N
	Industrial separation (natural gas processing, ammonia production)	Y
Transportation	Pipeline	Y
	Shipping	Y

[7] 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

[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). Available at http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf?d677-79e0

CCS Component	CCS Technology	Technical Feasibility
Geological Storage	Enhanced Oil Recovery (EOR)	Y
	Gas or oil fields	N*
	Saline formations	N*
	Enhanced Coal Bed Methane Recovery (ECBM)	N*
Ocean Storage	Direct injection (dissolution type)	N*
	Direct injection (lake type)	N*
Mineral carbonation	Natural silicate minerals	N*
	Waste minerals	N*
Large scale CO_2 Utilization/Application		N*

* Both geologic storage and large scale CO_2 utilization technologies are in the research and development phase and currently commercially unavailable.[9]

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

- Use of Low Carbon Fuels (up to 100% for fuels containing no carbon),
- CO_2 capture and storage (up to 90%),
- Heater Design (up to 10%),
- Air/Fuel Control (5-25%),
- Periodic tune-up (up to 10% for boilers),
- Product Heat Recovery (does not directly improve heater efficiency).

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. Fuels used in industrial process and power generation typically coal, fuel oil, natural gas, and process fuel gas. Of these natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emissions factor in lb/MMBtu about 55% of that of subbituminous coal. Some processes produce significant quantities of hydrogen, which produces no CO_2 emissions when burned. Thus, use of a completely carbon-free fuel such as 100% hydrogen, has the potential of reducing CO_2 emissions by 100%. Hydrogen is not produced from the processes at the Mont Belvieu Complex, and therefore is not a viable fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters. CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus considered to be the second most effective control method. 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 Energy Efficiency Improvement and Cost Saving Opportunities for the

[9] U.S. Department of Energy, page 20-23

Petrochemical Industry: An ENERGY STAR Guide for Energy and Plant Managers (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008). This report addressed improvements to existing energy systems as well as new equipment; thus, the higher end range of the stated efficiency improvements that can be realized is assumed to apply to the existing (older) facilities, with the lower end of the range being more applicable to new heater designs. Product heat recovery involves the use of heat exchangers to transfer the excess heat that may be contained in product streams to feed streams. Pre-heating of feed streams in this manner reduces the heat requirement of the downstream process unit (e.g., a distillation column) which reduces the heat required from process heaters. Where the product streams require cooling, this practice also reduces the energy required to cool the product stream.

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

Use of Low Carbon (Natural Gas) Fuel

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.

Carbon Capture and Sequestration

EPA considers CCS to be an available control option for high-purity CO_2 streams that merits initial consideration as part of the BACT review process, especially for new facilities. As noted in EPA's GHG Permitting Guidance, a control technology is "available" if it has a potential for practical application to the emissions unit and the regulated pollutant under evaluation. Thus, even technologies that are in the initial stages of full development and deployment for an industry, such as CCS, can be considered "available" as that term is used for the specific purposes of a BACT analysis under the PSD program. In 2010, the Interagency Task Force on Carbon Capture and Storage was established to develop a comprehensive and coordinated federal strategy to speed the commercial development and deployment of this clean coal technology. As part of its work, the Task Force prepared a report that summarized the state of CCS and identified technical and non-technical challenges to implementation.[10] EPA, which participated in the Interagency Task Force, supported the Task Force's conclusion that although current technologies could be used to capture CO_2 from new and existing plants, they were not ready for widespread implementation at all facility types. This conclusion was based primarily on the fact that the technologies had not been demonstrated at the scale necessary to establish confidence in their operations. EPA Region 6 has completed a research and literature review and has found that

[10] See *Report of the Interagency Task Force on Carbon Capture and Storage* available at http://www.epa.gov/climatechange/policy/ccs_task_force.html

nothing has changed dramatically in the industry since the August 2010 report and there is no specific evidence of the feasibility and cost-effectiveness of a full scale carbon capture system for the project and equipment proposed by Enterprise.

Enterprise developed a cost analysis for CCS that provided the basis for eliminating the technology as a viable control option in step 4 of the BACT process based on economic costs and environmental impacts. The recovery and purification of CO_2 from the stack gases would necessitate significant additional processing, including energy, and environmental/air quality penalties, to achieve the necessary CO_2 concentration for effective sequestration. The additional process equipment required to separate, cool, and compress the CO_2, would require a significant additional and power expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, including heaters, engines, and/or combustion turbines. Electric driven compressors could be used to partially eliminate additional emissions from the Mont Belvieu Complex. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or reduce the net amount GHG emission reduction, making CCS even less cost effective than expected.

The majority of the cost was attributed to the capture and compression facilities that would be required. The total annual cost of CCS would be $17,000,000 per year. EPA Region 6 reviewed Enterprise's CCS cost estimate and believes it adequately approximates the cost of a CCS control for this project and demonstrates those costs are prohibitive in relation to the overall cost of the proposed project without CCS, which is estimated at $500,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an overall annualized cost of about $47,200,000 without. The annualized cost of CCS would be at least a 33% increase in this cost, and thus CCS has been eliminated as BACT for this project an economically prohibitive.

Economic impacts notwithstanding, Enterprise also shows that CCS can have a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase emissions of GHGs, NOx, CO, VOC, PM_{10}, and SO_2 because of the increases energy needed to operate the CCS controls. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) area of ozone non-attainment and the generation of additional NOx and VOC could have exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, CCS could also be eliminated based on its environmental impacts, since its use would cause an increase in emissions of NOx and VOCs to the HGB non-attainment area airshed.

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.

Air/Fuel Controls

Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than is 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.

Periodic Heater Tune-ups

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.

Product 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.

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 (ETC), Jackson County Gas Plant Ganado, TX	Four Natural Gas Processing Plants	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 following specific BACT practices are proposed for the heaters:

- *Heater Design – Hot Oil Heaters* – The hot oil heaters shall be designed to achieve high thermal efficiencies. The proposed hot oil heaters shall maintain an 85% thermal efficiency on a 12 month rolling average basis, excluding malfunction and maintenance periods.
- *Heater Design – Hot Oil and Regenerative Heaters* – The heaters shall be designed to maximize heat transfer efficiency to the hot oil and regeneration streams and reduce heat loss. Ceramic fiber blankets and Kaolite™ of various thickness and density will be used where feasible on all heater surfaces. These insulation materials will reduce heat loss producing significant savings in furnace fuel consumption.
- *Periodic Tune-up* – Clean burner tips and convection tubes as needed, but to occur no less frequently than annually.
- *Heater Air/Fuel Control* – Install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency on the hot oil heaters. Install, utilize, and maintain an O_2 analyzer on the hot oil heaters to allow manual adjustment of the air damper to control the air/fuel ratio to maximize combustion efficiency.
- *Product Heat Recovery* – Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream.

- *Low Carbon Fuel* – Natural gas will be the only fuel fired in the proposed heaters. It is the lowest carbon fuel available for use at the complex.

BACT Limits and Compliance:

Enterprise shall demonstrate compliance with an 85% thermal efficiency on the hot oil heaters, which corresponds to a permit limit of 73,058 tpy CO_2e. The hot oil heaters will be continuously monitored for exhaust temperature, fuel temperature, ambient temperature, and excess oxygen. Thermal efficiency will be calculated for each operating hour from these parameters using equation G-1 from American Petroleum Institute (API) methods 560 (4^{th} ed.) Annex G. Efficient heater design and good combustion practices of the regenerative heaters corresponds to a permit limit of 14,872 tpy CO_2e.

Both 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.

Enterprise will maintain records of heater tune-ups, burner tip maintenance, O_2 analyzer calibrations and maintenance for all heaters. In addition, records of fuel temperature, ambient temperature, and stack exhaust temperature will be maintained for the hot oil heaters.

Enterprise will demonstrate compliance with the CO_2 limits for all heaters based on metered fuel consumption and using the average high heat value (HHV) calculated according to the requirements at§98.33(a)(2)(ii), and the default CO_2 emission factor 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:

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.

The proposed permit also includes an alternative compliance demonstration method, in which Enterprise 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 most (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 12-month rolling basis.

An initial stack test demonstration will be required for CO_2 emissions from each emission unit. An initial stack test demonstration for CH_4 and N_2O emissions is not required because the CH_4 and N_2O emission 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, making initial stack testing impractical and unnecessary.

X. Flare (SK25.001)

The two proposed fractionation units and the proposed DIB unit will each have vents that will be routed to a new flare (SK25.001) for control. The flare is air assisted with a hydrocarbon destruction and removal efficiency of 99.5%. These streams contain VOCs that when combusted by the flare produce CO_2 emissions. The flare's pilots are fueled by pipeline quality natural gas.

Step 1 – Identification of Potential Control Technologies for GHGs

- *Flaring Minimization* – Minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practices.
- *Proper Operation of the Flare* – 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.

Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Section X, Step 1 are considered technically feasible.

Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Flare minimization and proper operation of the flare are potentially equally effective but have case-by-case effectiveness that cannot be quantified to allow ranking.

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

Use of an analyzer(s) to determine the heating value of the gas to allow continuous determination of the amount of natural gas needed to maintain a minimum heating value of 300 Btu/scf to insure proper destruction of VOCs ensures that excess natural gas is not unnecessarily flared. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental impacts associated with this option. Proper design of the process equipment to minimize the quantity of waste gas sent to the flare also has no negative economic or environmental impacts.

Step 5 – Selection of BACT

Enterprise proposes to use both identified control options to minimize GHG emissions from flaring of process vents from the proposed facilities. The following specific BACT practices are proposed for the low profile flare:

- *Flaring Minimization* – The proposed process facilities will be designed to minimize the volume of the vent stream from the regenerant reflux drum, which is the primary source of waste gas sent to the flare.
- *Proper Operation of the Flare* – Flow rate and gas composition analyzers shall be used to continuously monitor the combined waste gas stream sent to the flare from the proposed and other existing facilities to determine the quantity of natural gas required to maintain a minimum heating value of 300Btu/scf. The flow rate and gas composition analyzer shall continuously record the molecular weight and mass flow rate of the flare gas.

Use of these practices corresponds with a permit limit of 65,542 tpy CO_2e.

XI. Process Fugitives (FRAC F EFa and FRAC F EFb)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 22 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 only identified control technology for process fugitive emissions of CO_2e 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

Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that occur as process fugitives is clearly cost prohibitive. However, if an LDAR program is being implemented for VOC control purposes, it will also result in effective control of the small amount of GHG emissions from the same piping components. Enterprise uses TCEQ's 28LAER[11] 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

Due to the negligible amount of GHG emissions from process fugitives, the only available control, implementation of an LDAR program, is clearly not cost effective, and BACT is determined to be no control. However, process lines in VOC service are proposed to incorporate the TCEQ 28LAER leak detection and repair (LDAR) program for fugitive emissions control in the PSD permit to be issued by TCEQ. Process lines contribute insignificant quantities of GHGs,

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[11] 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.

less than 0.01% of project CO_2e emissions, and since they are proposed in the governing permit for lowest achievable emission rate controls, process lines in VOC service in the two proposed fractionation units, EPA concurs with Enterprise assessment that using the TCEQ 28LAER LDAR program is an appropriate control of GHG emissions. As noted above, LDAR programs would not normally be considered for control of GHG emissions alone due to the negligible amount of GHG emissions from fugitives, and while the existing LDAR program is being imposed in this instance, the imposition of a numerical limit for control of those negligible emissions is not feasible.

XII. 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 Enterprise and its consultant, Whitenton Group, Inc., as non-federal representatives for purposes of preparation of the BA and for conducting informal consultation.

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 the proposed permit will have no effect on any of the ten (10) listed species, as the occurrence of any of these species within a 3-mile radius of the facility is highly improbable. The project site is approximately twenty-five (25) miles from the nearest coastline and therefore any species associated with the coast or Gulf waters are unaffected; this includes the piping plover and all listed marine species. There have never been sightings/occurrences of the Louisiana black bear, the red wolf nor Sprague's pipit within the 3-mile action radius of the construction site. In fact, the closest sighting of any of these species was Sprague's pipit and it was approximately twenty-eight (28) miles away from the project site.

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

XIII. 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 Atkins, Enterprise's consultant, submitted on July 10, 2012. After considering a report submitted by the applicant, EPA Region 6 determines no such properties will be affected by its permit action because none are present in the action area. Before that report was submitted to EPA, the Texas Historical Commission provided Enterprise written concurrence on the report and its conclusion that no such properties are present on January 20, 2012. Upon receipt of the report, 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 were interested 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 tribal requests for participation as a consulting party or comments about the project.

In the report, Enterprise conducted an archaeological survey within a three (3) kilometer radius of the site of construction as documented using Texas Archaeological Research Laboratory (TARL), THC's Restricted Archaeological Sites Atlas, and the National Park Service's National Register of Historic Places (NHRP) as well as a pedestrian survey of the site. Based on the information provided in the cultural resources report, three historic sites were found within the 3-kilometer radius, they were the First United Methodist Church and Cemetery of Mont Belvieu originally known as Barbers Hill, the Williams Cemetery and the Fisher Cemetery. All were found within 2.50-2.75 kilometers from the project site. However, no structures were found at the project site that met the criteria for inclusion in the National Register located in 36 CFR 60.4. This is because they are not significant from architectural or artistic distinction or historical importance or value, nor are they associated with a historic person or event, or a birthplace or grave of a historical figure of outstanding importance. Further, the site has been subject to many disturbances associated with previous construction activities related to oil and gas industry. Finally, the property is not of exceptional significance.

EPA Region 6 determines this project will have no effect on properties eligible for the National Register. EPA will provide a copy of this report to the State Historic Preservation Officer for consultation and concurrence with this determination.

XIV. 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.

XV. Conclusion and Proposed Action

Based on the information supplied by Enterprise, 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 Enterprise a PSD permit for GHGs for the facility, 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

APPENDIX

Annual Facility Emission Limits

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

Table 1. Facility Emission Limits

FIN	EPN	Description	GHG Mass Basis		TPY CO_2e[2,3]	BACT Requirements
				TPY[2]		
HR15.001A	HR15.001A	Hot Oil Heater	CO_2	72,987	73,058	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.35		
			N_2O	0.14		
HR15.001B	HR15.001B	Hot Oil Heater	CO_2	72,987	73,058	Minimum Thermal Efficiency of 85%. See permit condition III.A.1.r.
			CH_4	1.35		
			N_2O	0.14		
HR15.002A	HR15.002A	Regenerant Heater	CO_2	14,858	14,872	Use of Good Combustion Practices. See permit condition III.A.1.d. through III.A.1.j.
			CH_4	0.28		
			N_2O	0.03		
HR15.002B	HR15.002B	Regenerant Heater	CO_2	14,858	14,872	Use of Good Combustion Practices. See permit condition III.A.1.d. through III.A.1.j.
			CH_4	0.28		
			N_2O	0.03		
SK25.001	SK25.001	Flare	CO_2	62,494	62,542	Use of Good Combustion Practices. See permit condition III.A.2.
			CH_4	0.68		
			N_2O	0.11		
FRAC F EFa and FRAC F EFb	FRAC F EFa and FRAC F EFb	Fugitive Process Emissions	CH_4	Not Applicable	Not Applicable	Implementation of LDAR Program. See permit condition III.A.3.
Totals[4]			**CO_2**	**238,186**	**CO_2e 238,425**	
			CH_4	**4.99**		
			N_2O	**0.43**		

1. Compliance with the annual emission limits (tons per year) is based on a 12-month rolling 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. 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.