US EPA ARCHIVE DOCUMENT

Enterprise Products

ENTERPRISE PRODUCTS PARTNERS L.P.
ENTERPRISE PRODUCTS HOLDINGS LLC
(General Partner)

ENTERPRISE PRODUCTS OPERATING LLC

February 12, 2013

Federal Express

Mr. Jeff Robinson
Chief, Air Permit Section
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, Texas 75202-2733

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AIR PERMITS SECTION
6PD-R

RE: Application for PSD Air Quality Permit
Greenhouse Gas Emissions
Fractionation Units IX and X
Enterprise Products Operating LLC
Mont Belvieu, Chambers County, Texas
RN 102323268
CN 603211277
TCEQ Account No. CI-0008-R

Dear Mr. Robinson:

Enterprise Products Operating LLC (Enterprise) is submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas emissions from the proposed Fractionation Units IX and X at our Mont Belvieu Complex.

A State NSR permit application for other regulated pollutants has been submitted to TCEQ. Enterprise and our consultant, RPS, are committed to working with EPA to ensure a timely review of our permit application. We are available to meet with you at your convenience in your offices to discuss the project and answer any questions you may have.

Should you have questions concerning this application, or require further information, please do not hesitate to contact Edwin Bergmann our Sr. Permit Engineer (713) 381-5807, or me directly at (713) 381-5437.

Yours truly,

Chris Benton
Manager, Environmental Permitting

/sjn
enclosure
cc: Ms. Melanie Magee, EPA Region 6

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713.381.6500

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Application for
Prevention of Significant Deterioration
Air Permit
for
Greenhouse Gas Emissions

Enterprise Mont Belvieu Complex
Fractionation Units IX and X

Submitted by

Enterprise Products Operating LLC
P.O. Box 4324
Houston, Texas 77210-4324

February 2013

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Section 1
Introduction

Enterprise Products Operating LLC (Enterprise) currently operates the Mont Belvieu Complex, an oil and gas production facility in Chambers County. Enterprise proposes to construct two new fractionation process units (Fracs IX and X) at the Mont Belvieu Complex. The new fractionation facilities will include:

- Two Fractionation Unit deethanizer distillation columns,
- Two Fractionation Unit depropanizer distillation columns,
- Two Fractionation Unit debutanizer distillation columns,
- Two gas fired hot oil heaters,
- Two gas fired regenerant gas heaters,
- Cooling towers,
- New flare to treat process vents from the (EPN SK25.002),
- Ancillary tanks,
- Natural gas process fugitives.

A New Source Review permit application was submitted to TCEQ for this project on February 1, 2013. The project emissions increase or net emissions increase of all PSD and NNSR pollutants for which TCEQ has approved permitting programs are below their respective applicability thresholds; therefore, the TCEQ permit application is for a "state only" permit. However, the project will result in a significant net emissions increase for greenhouse gas (GHG) emissions, for which TCEQ has not implemented a PSD permitting program. The purpose of this permit application is to obtain a PSD permit from EPA for the GHG emissions associated with the project.

This document constitutes Enterprise's GHG PSD permit application for the modifications described above. Because the EPA has not developed application forms for GHG permitting, TCEQ forms are used where deemed appropriate. The application is organized as follows:

Section 1 identifies the project for which authorization is requested and presents the application document organization.

Section 2 contains administrative information and completed TCEQ Federal NSR applicability Tables 1F, 2F, and 3F.

Section 3 contains an area map showing the facility location and a plot plan showing the location of each emission points with respect to the plant property.

Section 4 contains more details about the proposed modifications and changes in operation and a brief process description and simplified process flow diagram.

Section 5 describes the basis of the calculations for the project GHG emissions increases and includes the proposed GHG emission limits.

Section 6 includes an analysis of best available control technology for the new sources of GHG emissions.

Appendix A contains GHG emissions calculations for the affected facilities.

Appendix B contains the results of an RBLC database search for GHG controls used on gas fired heaters and boilers.

Section 2
Administrative Information and PSD Applicability Forms

This section contains the following forms:

- Administrative Information
- TCEQ Table 1F
- TCEQ Table 2F
- TCEQ Table 3F

Tables 1F, 2F and 3F are federal NSR applicability forms. Because this application covers only GHG emissions, and PSD permitting of other pollutants is being conducted by TCEQ, these forms only include GHG emissions. As shown in both the Table 1F and 2F, GHG emissions from the project exceed 75,000 tpy of CO_2e; therefore, a Table 3F, which includes the required netting analysis, is also included. The net increase in GHG emissions exceeds 75,000 tpy of CO_2e; therefore, PSD review is required.

Administrative Information

A. Company or Other Legal Name: Enterprise Products Operating LLC		
B. Company Official Contact Name (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Dr.): Mr. Graham Bacon		
Title: Senior Vice President of Operations		
Mailing Address: P.O. Box 4324		
City: Houston	State: TX	ZIP Code: 77210
Telephone No.: 713-381-6595	Fax No.: 713-880-6660	E-mail Address: snolan@eprod.com
C. Technical Contact Name: Mr. Chris Benton		
Title: Manager – Environmental Permitting		
Company Name: Enterprise Products Operating LLC		
Mailing Address: PO Box 4324		
City: Houston	State: TX	ZIP Code: 77210
Telephone No.: 281-381-5437	Fax No.: 713-880-6660	E-mail Address: crbenton@eprod.com
D. Facility Location Information:		
Street Address: 10207 FM 1942		
If no street address, provide clear driving directions to the site in writing:		
City: Mont Belvieu	County: Chambers	ZIP Code: 77580
E. TCEQ Account Identification Number (leave blank if new site or facility): CI 0008-R		
F. TCEQ Customer Reference Number *(leave blank if unknown)*: CN6032211277		
G. TCEQ Regulated Entity Number *(leave blank if unknown)*: RN102323268		
H. Site Name: Mont Belvieu Complex		
I. Area Name/Type of Facility: Fractionation Units IX and X		☒ Permanent ☐ Portable
J. Principal Company Product or Business: Natural gas liquids processing		
K. Principal Standard Industrial Classification Code: 1321 – Natural Gas Liquids		
L. Projected Start of Construction Date: 11/01/2013	Projected Start of Operation Date: 07/01/2014	
SIGNATURE		
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief.		
NAME: Mr. Graham Bacon, Senior Vice President of Operations		
SIGNATURE: *Original Signature Required*		
DATE: 2/11/13		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date:	**February 2013**
Company: **Enterprise Products Operating LLC**		
RN: **102323268**	Facility Location: **10207 FM 1942**	
City: **Mont Belvieu**	County: **Chambers**	
Permit Unit I.D.: **Fractionation Units IX & X**	Permit Name: **Mont Belvieu Complex**	
Permit Activity: New Source ___ Modification **X**		
Project or Process Description: **Fractionation Units IX and X**		

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS											
	Ozone		CO	PM	PM_{10}	$PM_{2.5}$	NO_x	SO_2	H_2S	TRS	Pb	Other[1]
	VOC	NO_x										
Nonattainment? (yes or no)	Yes	Yes	No	No	No	No	No	No	NA	NA	No	GHG
Existing site PTE (tpy)?												>100,000
Proposed project emission increases (tpy from 2F)[2]												**230,182**
Is the existing site a major source? [3]If not, is the project a major source by itself?	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA
Significance Level (tpy)	5	5	100	25	15	10	40	40	10	10	0.6	75,000
If site is major, is project increase significant?												Yes
If netting required, estimated start of construction?							**1-Nov-13**					
Five years prior to start of construction	See Note Below						**12-Oct-12**		contemporaneous			
Estimated start of operation							**1-Jul-14**		period			
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	**230,182**
FNSR APPLICABLE? (yes or no)												Yes

Note: Eagleford Frac GHG PSD Permit wiped slate clean and reset start of contemporaneous period to 10/12/2012.

1 Other PSD pollutants.

2 Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR § 51.166(b)(23).

3 Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR § 51.166(b)(1).

The representations made above and on the accompanying tables are true and correct to the best of my knowledge.

Signature | Senior Vice President of Operations (Title) | 2/11/13 (Date)

TCEQ - 10154 (Revised 10/08) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v1)

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	GHG	Permit No.:	TBD
Baseline Period:	NA	Project Name:	Fractionation Units IX and X

December A B

	Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3] (tons/yr)	Baseline Emissions[4] (tons/yr)	Proposed Emissions[5] (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A)[6] (tons/yr)	Correction[7] (tons/yr)	Project Increase[8] (tons/yr)
	FIN	EPN	Facility Name								
1	HR20.001	HR20.001	Hot Oil Heater	TBD		-	80,319	80,319	80,319	0	80,319
2	HR21.001	HR21.001	Hot Oil Heater	TBD		-	80,319	80,319	80,319	0	80,319
3	HR20.002	HR20.002	Regenerant Heater	TBD		-	16,351	16,351	16,351	0	16,351
4	HR21.002	HR21.002	Regenerant Heater	TBD		-	16,351	16,351	16,351	0	16,351
5	FRAC F IX	FRAC F IX	Process Fugitives	TBD	-	-	11	11	11	0	11
6	FRAC F X	FRAC F X	Process Fugitives	TBD	-	-	11	11	11	0	11
7	SK25.002	SK25.002	Flare	TBD	-	-	36,821	36,821	36,821	0	36,821
8											
9											
10											
11											
12											
13											
										Page Subtotal[9]:	230,182
										Project Total:	230,182

Table 3F
Project Contemporaneous Changes

Company: **Enterprise Products Operating LLC**

Permit Application No. **TBD**

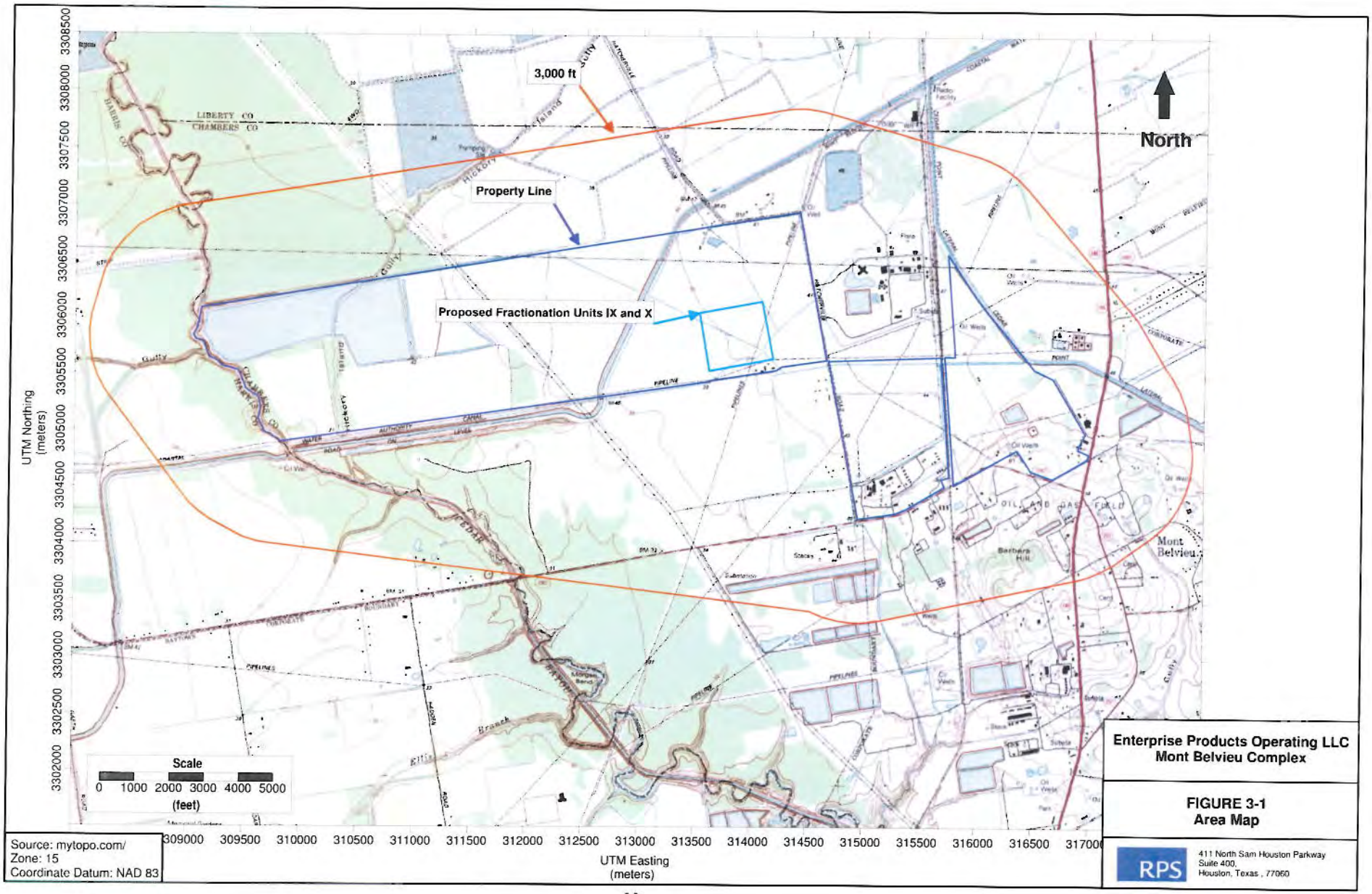
Criteria Pollutant: **GHG**

No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED		PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A	B	C	
		FIN	EPN			PROPOSED EMISSIONS (tons / year)	BASELINE EMISSIONS (tons / year)	DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	Jul 2014	HR20.001	HR20.001	TBD	Fractionation Units IX and X	80,319	0	80,319	80,319
2	Jul 2014	HR21.001	HR21.001	TBD	Fractionation Units IX and X	80,319	0	80,319	80,319
3	Jul 2014	HR20.002	HR20.002	TBD	Fractionation Units IX and X	16,351	0	16,351	16,351
4	Jul 2014	HR21.002	HR21.002	TBD	Fractionation Units IX and X	16,351	0	16,351	16,351
5	Jul 2014	FRAC F IX	FRAC F IX	TBD	Fractionation Units IX and X	11	0	11	11
6	Jul 2014	FRAC F X	FRAC F X	TBD	Fractionation Units IX and X	11	0	11	11
7	Jul 2014	SK25.002	SK25.002	TBD	Fractionation Units IX and X	36,821	0	36,821	36,821
								0	0
								0	0
								0	0
								0	0
								0	0
								PAGE SUBTOTAL:	230,182
Summary of Contemporaneous Changes								TOTAL :	**230,182**

Note: Slate was wiped clean by Eagleford Frac GHG PSD Permit, therefore, start of contemporaneous period is reset after that permit

Section 3
Area Map and Plot Plan

An Area Map showing the location of the Mont Belvieu Complex is presented in Figure 3-1. A plot plan showing the location of the new facilities is presented in Figure 3-2.

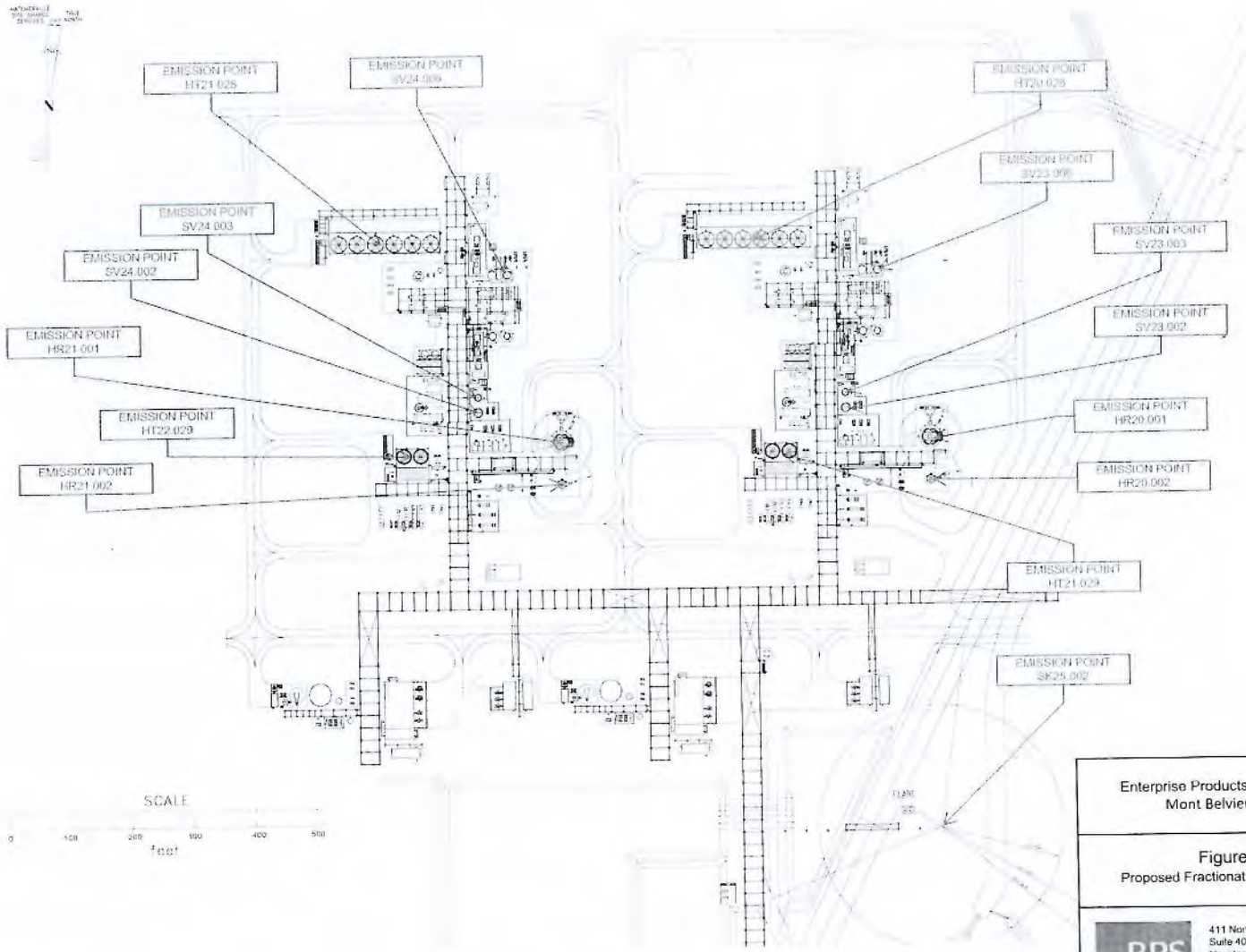


Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83

Enterprise Products Operating LLC
Mont Belvieu Complex

FIGURE 3-1
Area Map

RPS
411 North Sam Houston Parkway
Suite 400,
Houston, Texas , 77060



Enterprise Products Operating LLC
Mont Belvieu Complex

Figure 3-2
Proposed Fractionation Units IX and X

RPS

411 North Sam Houston Parkway
Suite 400,
Houston, Texas , 77060.

Section 4
Project and Process Description

The natural gas liquids (NGL) fractionation units at the Mont Belvieu Complex to be authorized by this permit will be used to separate an NGL feed into separate ethane, propane, butane, and gasoline fractions. A simplified process flow diagram for the fractionation units is shown in Figure 4-1. Each unit consists of a number of fractionation columns and other operations as described below. Each of the two fractionation units will have a nominal feed capacity of 110,000 barrels per day

The pipeline feed mixture is processed in the feed filter, feed coalescer, 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. Propylene vapor from the Deethanizer condenser is first compressed in a two-stage machine and then is condensed in a wet-surface air cooler (EPNs HT21.028 and HT22.028). The liquid propylene is then sub-cooled against low-temperature ethane before being fed back to the Deethanizer column condenser as 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 takes 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. Condensing for the column is provided by a heat pump circuit and a wet-surface air cooler. The propane heat pump circuit exchanges against the Depropanizer side reboiler and two reboilers attached to the Deethanizer column. The wet-surface air coolers (EPNs HT21.029 and HT22.029) are used to sub-cool the condensed propane. 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

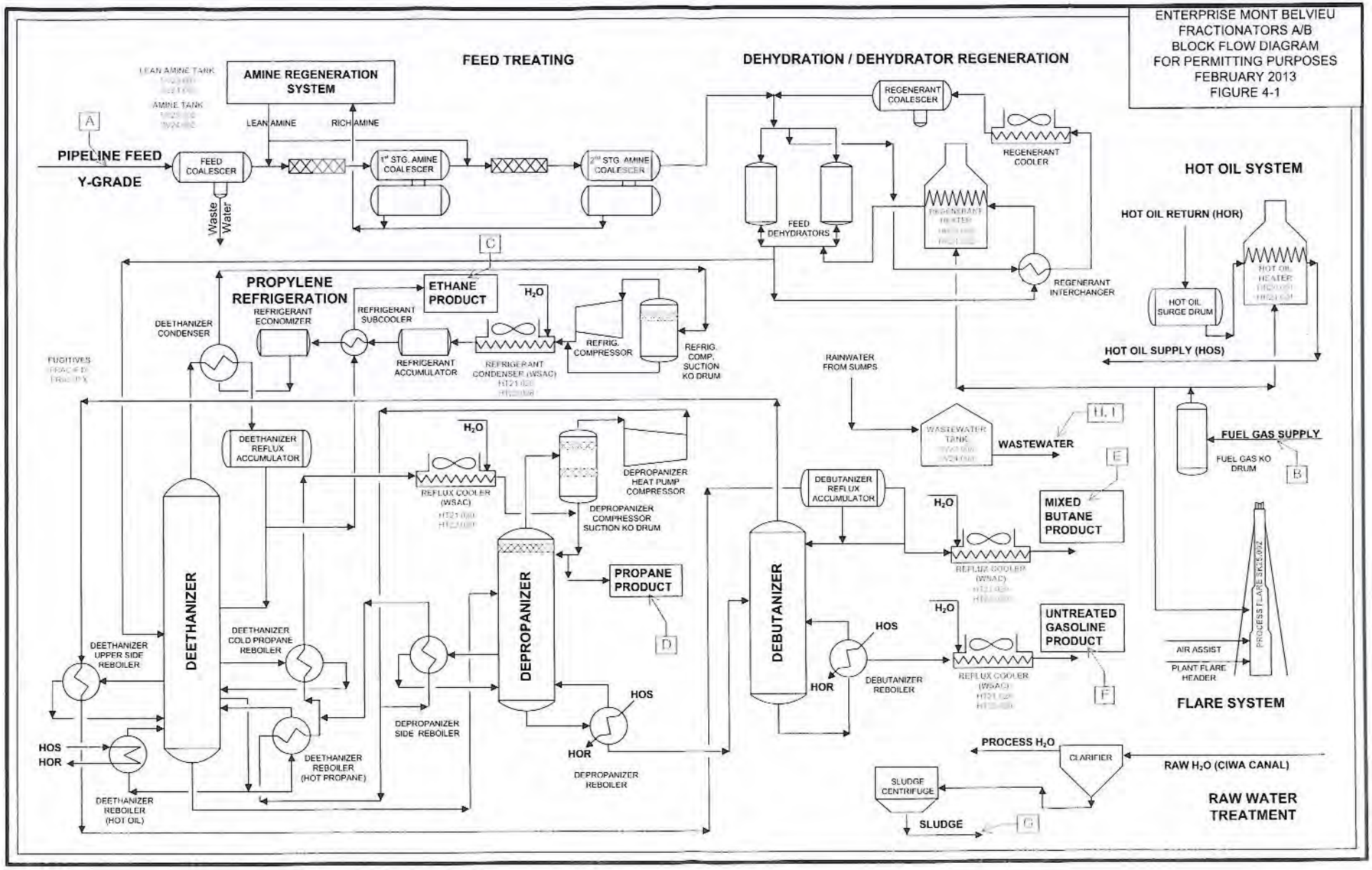
isobutane), and a bottoms gasoline stream which contains pentanes and heavier. Part of the overhead butane stream is refluxed back to the column and the balance is sent to storage tanks as an intermediate feed for other units or as commercial butane product. The bottoms gasoline is routed to existing gasoline treating facilities. Condensing for the Debutanizer is provided by the Deethanizer Upper Side Reboiler, and heat for fractionation in the Debutanizer is provided by a hot oil reboiler at the bottom of the column.

Hot oil used in the column reboilers is provided by gas-fired hot oil heaters (EPNs HR20.001 and HR21.001). 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 heaters (EPNs HR20.002 and HR21.002).

Ancillary to each of the fractionators will be four tanks. One tank in each Frac will store 85% diethanolamine (EPNs SV23.002 and SV24.002), one will store 25% diethanolamine (EPNs SV23.003 and SV24.003), and one to store wastewater (EPNs SV23.006 and SV24.006). Each of these tanks will store material with a VOC vapor pressure of less than 0.00002 psia and have no applicable requirements.

Emission sources from this process include process emissions from heaters, cooling towers, tanks, equipment leak fugitives (EPNs FRAC F IX and FRAC F X), and process vents that will be routed to a flare (EPN SK25.002). The requirements of NSPS Subparts A and KKK and TCEQ Chapters 111, 112, 115, and 117 apply to the operations of each Fractionation Unit.

ENTERPRISE MONT BELVIEU
FRACTIONATORS A/B
BLOCK FLOW DIAGRAM
FOR PERMITTING PURPOSES
FEBRUARY 2013
FIGURE 4-1



Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from new and modified facilities associated with the project. GHG emission calculations methods are also described, and the resulting GHG emission rates are presented in Table 5-1 for each emission point. Emissions calculations are included in Appendix A.

5.1 Hot Oil and Regenerant Heater Emissions

There will be four new gas fired process heaters constructed for the project: two Hot Oil Heaters (EPNs HR20.001 and HR21.001) and two Regenerant Heaters (EPNs HR20.002 and HR21.002). Fuel for the heaters will consist or natural gas, fuel gas from a flare gas recovery project, and ethane. Annual GHG emissions were calculated based on the maximum fuel firing rate of each heater occurring continuously (8,760 hr/yr) all year. CO_2 emissions were calculated based on the carbon content of the fuel using Equation C-5 in 40 CFR Part 98, Chapter C. Emissions of CH_4 and N_2O were calculated from emission factors from Table C-2 of Appendix A to 40 CFR Part 98, Chapter C.

5.2 Flare Emissions

The two proposed frac units will each have vents that will be routed to a new flare (EPN SK25.002) for control. These streams contain VOCs that when combusted by the flare produce CO_2 emissions. Natural gas used as assist gas to maintain the minimum heating value required for complete combustion also contains hydrocarbons, primarily methane, that also produce CO_2 emissions when burned. Any unburned methane from the flare will also be emitted to the atmosphere, and small quantities of N_2O emissions can result from the combustion process. Emissions of these pollutants were calculated based on the carbon content of the waste streams sent to the flare and of the natural gas used for assist with the same equations and emission factors from 40 CFR Part 98 that were used for the gas fired heaters. These equations and factors were applied to the maximum projected annual waste gas and natural gas flow rates to the flare.

5.3 Process Fugitive Emissions

Process fugitive (equipment leak) emissions consist of methane from the new piping components in the new Frac Unit (EPNs FRAC F IX and FRAC F X). The 28LAER leak detection and repair (LDAR) program will be applied to the new piping components associated with the Project. In addition, all flanges and connectors will be monitored quarterly using the same leak detection level used for valves. All emissions calculations utilize current TCEQ factors and methods in the TCEQ's *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.* Each fugitive component was classified first by equipment type (valve, pump, relief valve, etc.) and then by material type (gas/vapor, light liquid, heavy liquid). Uncontrolled emission rates were obtained by multiplying the number of fugitive components of a particular equipment/material type by the appropriate SOCMI emission factor. To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the 28LAER LDAR program. The methane emissions were then calculated by multiplying the total controlled emission rate by the weight percent of methane in the process streams. The fugitive emissions calculations are included in Appendix B.

Table 5-1 Proposed GHG Emission Limits

Description	EPN	CO_2e Emission Rate (tpy)	
		Natural Gas/ Fuel Gas	Ethane Fuel
Frac A Hot Oil Heater	HR15.001A	73,058	80,319
Frac B Hot Oil Heater	HR15.001B	73,058	80,319
Frac A Regenerant Heater	HR15.002A	14,872	16,351
Frac B Regenerant Heater	HR15.002B	14,872	16,351
Frac A Process Fugitives	FRAC F EFa	11	11
Frac B Process Fugitives	FRAC F EFb	11	11
Flare	SK25.001	36,821	36,821
Total*		**230,182**	

* Total is based on firing ethane in heaters.

Section 6
Best Available Control Technology

PSD regulations require that the best available control technology (BACT) be applied to each new and modified facility that emits an air pollutant for which a significant net emissions increase will occur from the source. The only PSD pollutant addressed in this permit application is GHG. The new facilities associated with the project that emit GHGs include two Hot Oil Heaters (EPNs HR20.001 and HR21.001), two Regenerant Heaters (EPNs HR20.002 and HR21.002)), and Process Fugitives (EPNs FRAC F IX and FRAC F X). There will also be GHG emissions from the combustion of new process vent streams in a new flare (EPN SK25.002). BACT applies to each of these new sources of GHG emissions.

The U.S. EPA-preferred methodology for a BACT analysis for pollutants and facilities subject to PSD review is described in a 1987 EPA memo (U.S. EPA, Office of Air and Radiation Memorandum from J.C. Potter to the Regional Administrators, December 1, 1987). This methodology is to determine, for the emission source in question, the most stringent control available for a similar or identical source or source category. If it can be shown that this level of control is technically or economically infeasible for the source in question, then the next most stringent level of control is determined and similarly evaluated. This process continues until the BACT level under consideration cannot be eliminated by any substantial or unique technical, environmental, or economic objections. In addition, a control technology must be analyzed only if the applicant opposes that level of control.

In an October 1990 draft guidance document (*New Source Review Workshop Manual (Draft)*, October 1990), EPA set out a 5-step process for conducting a top-down BACT review, as follows:

1) Identification of available control technologies;
2) Technically infeasible alternatives are eliminated from consideration;
3) Remaining control technologies are ranked by control effectiveness;
4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and
5) Selection of BACT.

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows the top-down approach.

6.1 Hot Oil and Regenerant Heaters

6.1.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the Mont Belvieu Complex, the existing heaters are designed to achieve high thermal efficiencies, which minimizes GHG emissions. The proposed new Hot Oil Heaters (140 MMBtu/hr each) are designed to achieve 89% thermal efficiency, and the Regenerant Heaters (28.5 MMBtu/hr each) are designed to achieve 80% thermal efficiency. These and other potentially applicable technologies to minimize GHG emissions from the heaters include the following:

- Periodic Tune-up – Periodically tune-up of 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 the heater 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 recovery usable heat from product streams reduces overall energy consumption and a reduction in the amount of fuel required by 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. Selecting low carbon fuels is a viable method of reducing GHG emissions.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

A RACT/BACT/LAER Clearinghouse (RBLC) search was also conducted in an attempt to identify BACT options that have been implemented or proposed for other similar gas fired combustion facilities. The results of this search are presented in Appendix B. No additional technologies were identified. The control methods identified in the search were limited to the first three options listed above (tune-ups, good design, and good combustion practice and operation). Information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers*

(Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used in the preparation of this analysis.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible; however, waste heat recovery is not considered to be a practical alternative for the proposed heaters. 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, with a resulting low exhaust gas temperature (393 °F) that does not contain sufficient residual heat to allow effective heat recovery. For example, use of flue gas heat recovery to preheat the heater combustion air is typically only considered practical if the exhaust gas temperature is higher than 650 °F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)). A more practical alternative to reduce heater demand in the proposed process is the use of heat exchangers throughout the process to utilize the heat from product streams to preheat feed streams to the various process units (See Figure 4-1 in the Process Description). This practice also reduces the energy required in the units used to cool the product streams. A portion of this energy reduction is in the form of purchased electricity. While this does not directly affect emissions from the heaters, a reduction in purchased electricity reduces the amount of GHG emissions produced from the combustion of coal or natural gas at the power plant where the electricity is produced. An alternative to purchasing power produced at a larger more efficient power plant is to install smaller, less efficient power generating facilities at the Mont Belvieu plant. Thus, the plant design to purchase electricity and minimize electricity and other energy needs through the use of heat exchangers is a more effective method of minimizing GHG emissions through heat recovery than recovery of the small amount of residual heat in the Hot Oil Heater exhausts. The Regenerant Heaters cannot be used effectively for waste heat recovery, as they are on/off cycled heater (design is firing about 8 hrs, and shut down for about 24 to 30 hrs). For these reasons, use of waste heat recovery on the heaters was eliminated from further consideration.

Carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities. However, for completeness, this control option is included in the remainder of this analysis, and the reasons that it is not considered viable are discussed in Section 6.1.4.

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The remaining technologies applicable to the proposed heater design in order of most effective to least effective include:

- 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; information not found for heaters), and
- Product Heat Recovery (does not directly improve heater efficiency).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial processes and power generation typically include 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 emission factor in lb/mmBtu about 55% of that of sub bituminous coal. Process fuel gas is a byproduct of chemical process, which typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/mmBtu for fuel gas compared to 53.02 kg/mmBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/mmBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not viable fuel for the proposed heaters, as the Mount Belvieu Complex does not contain coke ovens. Although Table C-2 includes a typical CO_2 factor of 59 kg/mmBtu for fuel gas, fuel gas composition is highly dependent on the process from which the gas is produced. 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%.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the 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 Petrochemical Industry: An ENERGY STAR Guide for Energy 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 of the range of 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.

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

Carbon Capture and Sequestration. As stated in Section 6.1.2, carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from natural gas fired facilities. This conclusion is supported by the BACT example for a natural gas fired boiler in Appendix F of EPA's *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010). In the EPA example, CCS is not even identified as an available control option for natural gas fired facilities. Also, on pages 33 and 44 of the Guidance Document, it states:

"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and 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). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs." The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1. Although the proposed facility is not one of the listed facility types for which CCS should be considered, it was further evaluated for the project to ensure that the analysis was complete.

CCS technology has been proposed for some recent gasification projects. In these processes, when coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. Further processing of the raw syngas to produce a final fuel product typically results in a concentrated CO_2 waste stream that is naturally ready for sequestration. Combustion of natural gas or ethane, as is proposed by

Enterprise, produces an exhaust stream that is less than 10% CO_2. Separation (purification) of the CO_2 from the heater combustion exhaust streams would require additional costly steps not otherwise necessary to the process. Coal also has a much higher carbon content than natural gas, and the captured carbon from coal gasification projects only represents the delta between natural gas and coal. Thus, while such projects may reduce GHG emissions compared to conventional methods of obtaining energy from coal, they result in no GHG emissions reduction relative to use of natural gas fuel as proposed for the Enterprise heaters.

As a final point, the viability of most proposed gasification project are highly dependent on government support. In contrast, the Enterprise project relies on market conditions for viability and is not guaranteed by the government.

Regardless of these differences, for completeness purposes, Enterprise has performed an order of magnitude cost analysis for CCS applied to the heaters addressed in this permit application. The results of the analysis, presented in Table 6-1, show that the cost of CCS for the project would be approximately $104 per ton of CO_2 controlled, which is not considered to be cost effective for GHG control. This equates to a total cost of about $18,000,000 per year the four heaters. The best estimate of the total capital cost of the two proposed fractionation units is $500,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $47,200,000. Thus the annualized cost of CCS would be almost 40% of this cost; which far exceeds the threshold that would make CCS economically viable for the project.

There are additional negative impacts associated with use of CCS for the proposed heaters. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy 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, but significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur from the associated power plant that produces the electricity. 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 shown in Table 6-1.

Based on both the excessive cost effectiveness in $/ton of GHG emissions controlled and the inability of the project to bear the high cost and the associated negative environmental and energy impacts, CCS is rejected as a control option for the proposed project.

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. The function and near steady state operation of the Hot Oil Heaters allows them to be designed to achieve "near best" thermal efficiency. The Regenerant Heaters will be in cyclic service that spans a 24 to 36 hour period. During this period, the heater heats up from cold or standby/pilots only (~0.4 mmBtu/hr) to the design case. Following this, over the operating cycle (~10 hrs) the heaters transition to the running case. To meet the CO and NO_x emission requirements which are dependent on the flue gas temperature for both the cases, the heaters have to be designed with a high heat flux/radiant section flue gas temperature at the design case which drives stack temperature up. With a very low inlet temperature at the design case, the efficiency is lower than typically expected since heat recovery is hampered due to design for significantly different operating cases.

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 needed to achieve these objectives reduces overall heater efficiency. Manual or automated air/fuel ratio controls are used to optimizes these parameters and maximize the efficiency of the combustion process. Automated controls are considered more effective than manual controls.

Periodic Heater Tune-ups. Periodic tune-ups of the heaters include:

- Preventive maintenance check of fuel gas flow meters annually,
- Preventive 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, this technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements.

Use of Low Carbon Fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the Mont Belvieu Complex and is currently considered a very cost effective fuel alternative. Natural gas is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Ethane is also an available fuel for the proposed heaters. There is currently an over-abundance of ethane being produced from natural gas production facilities. Some of this ethane can be used as feedstock to ethylene plants, but excess ethane still exists. The alternatives for use or disposal of this excess ethane include flaring it, removing less of it from natural gas, and using it as a fuel source at industrial facilities (such as the proposed fractionation units). All of these alternatives result in the same amount of CO_2 emissions when the ethane is ultimately burned. Flaring is the least desirable alternative as no heat benefit is gained, and there would be additional CO_2 emissions from combustion of the natural gas that it would otherwise replace. Ethane has a CO_2e emission factor of about 118 lb/mmBtu. Thus, using excess ethane available on the market as fuel in place of natural gas results in only about 11% more CO_2e emissions from the plant compared to an equivalent amount of natural gas, and no net increase in global CO_2e emissions. Ethane is also a very clean burning fuel with respect to criteria pollutants and thus has minimal environmental impact compared to other fuels.

Offgas that will be produced from the PSA Unit flare gas recovery project is also an available fuel for the proposed heaters. The carbon content of the offgas will be within the range bracketed by natural gas and the proposed ethane fuel. Since this gas is currently flared, using it as fuel results in no net increase in GHG emissions, and it only displaces an equivalent amount of natural gas that would otherwise burned in the proposed heaters.

6.1.5 Step 5 – Selection of BACT

Air/fuel controls and efficient heater design, and tune-ups performed as needed are currently utilized on the existing heaters at the Mont Belvieu Complex to maximize efficiency and thus reduce GHG emissions. These control practices are also included in the design of the new heaters and are thus part of the selected BACT. These technologies and additional BACT practices proposed for the heaters are listed below:

- Use of low carbon fuel. Natural gas, process fuel gas (from PSA flare gas recovery), and ethane will be the only fuels fired in the proposed heaters. This will result in CO_2e emission rates between about 118 and 131 lb/mmBtu of fuel burned. This emission rate

results in lower "global" CO_2e emissions compared to burning 100% natural gas and disposing of the process gas and excess ethane by other methods.

- Determine CO_2e emissions from the Hot Oil and Regenerant Heaters based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Good heater design 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. Kaolite™ is a super light low thermal conductivity insulation material consisting of vermiculite and Portland cement that reduces heat transfer producing significant savings in furnace fuel consumption.
- Based on the design conditions and the "process inlet to exit flue gas" approach temperature, the Hot Oil Heaters will be designed and operated to near-best efficiency while maintaining emissions limits. Any further design changes would result in a minimal incremental change in efficiency and has been analyzed as being non cost-effective. An approach temperature of 100°F is typical design practice when using carbon steel tubes and furthermore the stack temperature must be high enough to avoid the acid gas dew point of the flue gas. This typically results in a stack temperature no less than 325°F-350°F, thus dictating efficiency for the heater.
- Demonstrate Hot Oil Heater efficiencies by monitoring the 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) Method 560 (4^{th} edition) Annex G. An efficiency of 85% will be maintained on a 12-month rolling average basis, excluding malfunction and maintenance periods.
- The Regenerant Heaters will be designed and operated to achieve the maximum possible thermal efficiency considering their cyclic service.
- Install, utilize, and maintain an automated air/fuel control system to maximize combustion efficiency on the Hot Oil Heaters.
- Clean heater burner tips and convection tubes as needed.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year and air/fuel control analyzers once per quarter.
- 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. This will also reduce the energy requirement (primarily purchased electricity) needed to cool the product streams. Figure 4-1 in Section 4 of this permit application identifies points in the process where this technology will be used.

6.2 Flare

GHG emissions, primarily CO_2, are generated from the combustion of waste gas streams from the proposed units and assist natural gas used to maintain the required minimum heating value to achieve adequate destruction.

6.2.1 Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions from flaring is minimizing the quantity of flared waste gas and natural gas to the extent possible. The technically viable options for achieving this include:

- Flaring minimization – minimize the duration and quantity of flaring to the extent possible through good engineering design of the process and good operating practice.
- 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.
- Use of a thermal oxidizer in lieu of a flare.
- Use of a vapor recovery unit in lieu of a flare.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

Both flaring minimization and proper operation of the flare are considered technically feasible.

One of the primary reasons that a flare is consider for control of VOC in the process vent streams is that it can also be used for emergency releases. Although every possible effort is made to prevent such releases, they can occur, and the design must allow for them. A thermal oxidizer is not capable of handling the sudden large volumes of vapor that could occur during an upset release. A thermal oxidizer would also not result in a significant difference in GHG emissions compared to a flare. The same constraints exist with a vapor recovery unit. For this reason, even if a thermal oxidizer or vapor recovery unit was used for control of routine vent streams, the flare would still be necessary and would require continuous burning of natural gas in the pilots, which add additional CO_2, NO_x, and CO emissions.

A vapor recovery unit is not considered technically feasible for the amine regeneration stream, as it is not well suited to low levels of hydrocarbon in a large inert stream. A vapor recovery unit would require a chiller to condense the VOC in the stream. The stream contains significant amounts of CO_2 and water that would condense and cause icing of the equipment.

For these reasons, use of either a thermal oxidizer or vapor recovery unit is rejected as technically infeasible for the proposed project.

6.2.3 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.

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

Use of an analyzer(s) to determine the heating value of the flare 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.

6.2.5 Step 5 – Selection of BACT

Enterprise proposes use of both identified control options to minimize GHG emissions from flaring of process vents from the proposed facilities. Flare system analyzers will 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 300 Btu/scf and also to limit the quantity of natural gas use only what is needed to maintain 300 Btu/scf. The efficient use of natural gas will avoid the production of both unnecessary GHG emissions as well as criteria pollutants. The proposed process facilities will be designed to minimize the volume of the vent streams sent to the flare.

6.3 Process Fugitives

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from processes fugitives have been conservatively estimated to be 22 tpy as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.3.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for process fugitive emissions of CO_2e are 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.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

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 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.

6.3.5 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, Enterprise will implement TCEQ's 28LAER LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

Table 6-1. Approximate Cost for Post-Combustion Carbon Capture and Sequestration

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annual Cost
CO_2 Capture and Compression Facilities	$103	174,005	$17,922,527
CO_2 Transport Facilities (per 100 km of pipeline)[3]	$0.91	174,005	$15,834
CO_2 Storage Facilities	$0.51	174,005	$88,743
Total CCS System Cost	$104	NA	$18,027,104

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of Frac Plants without CCS	$500,000,000	0.0944	$47,196,463

1. Costs are from *Report of the Interagency Task Force on Carbon Capture (August, 2010)*. A range of costs was provided for transport and storage facilities; for conservatism, the low ends of these ranges were used in this analysis as they contribute little to the total cost. Reported costs in $/tonne were converted to $/ton.

2. Tons of CO_2 controlled assumes 90% capture of all CO_2 emissions from 2 Hot Oil Heaters and 2 Regenerant Heaters.

3. Pipeline costs are per 100 km of pipeline. It is conservatively assumed that a suitable storage location can be found within 10 km, which reduces the total cost for this component of the CCS system to a negligible amount.

4. Capital recovery factor based on 7% interest rate and 20 year equipment life.

Interest rate	7%
Equipent Life (yrs)	20

Section 7
Additional Impacts Analysis

PSD regulations require an Additional Impacts Analysis for projects that are subject to PSD review. In 40 CFR 52.21(o), it states that:

> (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.

This section of the application addresses these requirements.

7.1 Visibility, Soils, and Vegetation

The proposed project will not result in a significant increase in any air contaminant other than GHGs; therefore, the project is not subject to PSD review for any other pollutant. GHGs themselves are not known to have any direct impact on visibility, soils, and vegetation other than their possible impact associated with global warming, which EPA has ruled does not need to be evaluated for GHG PSD permits. However, emissions of other air pollutants from the project could potentially impact these resources. Because the project increases for all other pollutants are insignificant, it is concluded that their impact on visibility, soils, and vegetation is also insignificant.

7.2 Associated Growth

The proposed project will not significantly affect residential, commercial, or industrial growth in the area. Only 8-16 potential new hires are expected to be created by the addition of the proposed Fractionation IX and X facilities at the Mont Belvieu Complex. Even if these jobs were to be filled by individuals relocating to the area, it would result in a negligible impact on the existing infrastructure. Because these impacts will be negligible, the corresponding impact on air quality will also be negligible.

Appendix A

Emissions Calculations

Enterprise Operating Products LLC
Mont Belvieu Complex - Fracs IX and X
GHG Emissions

FIN	EPN	Description[1]	Flow Rate (MMBtu/yr)	Flow Rate (Fuel) (scf/yr)	Carbon Content (CC)	MW (lb/lbmol)	CO2 Emissions (tpy)[2]	CH4 Emissions (tpy)[2]	N2O Emissions (tpy)[2]	CO2e Emissions (tpy)[2]
HR20.001	HR20.001	Hot Oil Heater - NG	1,226,400	1,200,774,774	0.717	17.56	72,987	1.35	0.14	73,058
		Hot Oil Heater - Ethane	1,226,400	692,099,323	0.798	30.07	80,249	1.35	0.14	80,319
HR21.001	HR21.001	Hot Oil Heater - NG	1,226,400	1,200,774,774	0.717	17.56	72,987	1.35	0.14	73,058
		Hot Oil Heater - Ethane	1,226,400	692,099,323	0.798	30.07	80,249	1.35	0.14	80,319
HR20.002	HR20.002	Regen Heater - NG	249,660	244,443,436	0.717	17.56	14,858	0.28	0.03	14,872
		Regen Heater - Ethane	249,660	140,891,645	0.798	30.07	16,336	0.28	0.03	16,351
HR21.002	HR21.002	Regenerant Heater	249,660	244,443,436	0.717	17.56	14,858	0.28	0.03	14,872
			249,660	140,891,645	0.798	30.07	16,336	0.28	0.03	16,351
FRAC F IX	FRAC F IX	Fugitives					-	0.51	-	11
FRAC F X	FRAC F X	Fugitives					-	0.51	-	11
SK25.002	SK25.002	Flare								-
		Nat Gas	283,965	278,031,548	0.717	17.56	16,900	0.31	0.03	16,916
		FRAC Vent Gas	35,161	697,646,400	0.193	28.93	18,817	0.13	0.03	18,827
		Ethane (MSS)	823	468,406	0.798	30.07	54	0.003	0.001	55
		Propane (MSS)	892	357,462	0.817	44.09	62	0.003	0.001	62
		Butane (MSS)	364	112,361	0.826	58.12	26	0.001	0.0002	26
		Pentane (MSS)	12,400	3,214,036	0.832	72.15	932	0.04	0.01	935
						Total**:	229,980	5	0	230,182
						Total** CO2e:	229,980	100.16	121.38	230,182

[1] Offgas from PSA flare gas recovery project will also be fired in heaters. CO2e emissions will not exceed those represented for 100% ethane fuel.

[2] Note all emission rates are in units of short tons. Eq. C-5 in 40 CFR Part 98 Chapter C yields emissions in metric tons. Metric tons were converted to short tons by multiplying by 1.102311 short tons per metric ton.

** Totals are based on ethane firing in heaters as GHG emissions are highest with this fuel.

Operating Schedule: 8760 hr/yr
Natural Gas Heating Value: 1021 Btu/scf (hhv)
Vent Gas Heating Value: 55 Btu/scf (hhv)
Ethane Heating Value: 1772 Btu/scf (hhv)

Emission Factors:

Eq. C-5 from 40 CFR Part 98 Chapter C

$$CO_2 = \frac{44}{12} * Fuel * CC * \frac{MW}{MVC} * 0.001 \quad (Eq. C-5)$$

CO2 = CO2 emissions, metric tons/yr
Fuel = firing rate in mmscf/yr
MVC = 836.6 (per Part 98)
CC = as calculated below
MW = as calculated below

CH4 and N2O Emission factors from Table C-2 of Appendix A to 40 CFR Part 98 Chapter C

	kg CH4 /mmBtu	kg N2O/mmBtu
Natural Gas	0.001	0.0001
Vent/Process Gas	0.003	0.0006
kg to lb conversion factor		2.20462

CO2 Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

Vent and Fuel Gas Analyses

Component	Molecular Weight (lb/lb-mol)	Natural Gas Composition (mole %)	Vent Gas Composition (mole %)	Number of Carbons
H_2	2.000	0.0000		0
N_2	28.013	1.3645		0
O_2	31.999	0.2324		0
CO	28.010	0.0124		1
CO_2	44.01	1.4665	40.30	1
H2O	18.02	0.0000	56.99	0
Methane	16.04	92.9606	0.04	1
Ethane	30.07	2.6126	2.02	2
Propane	44.09	0.6918	0.59	3
i-Butane	58.12	0.1946	0.00	4
n-Butane	58.12	0.1751	0.01	4
i-Pentane	72.15	0.0662	0.00	5
n-Pentane	72.15	0.0448	0.00	5
Hexane+	86.17	0.1785	0.05	6
	MW (lb/lbmole)	17.56	28.93	
	Carbon Content (kg C/kg Fuel)	0.717	0.193	

Enterprise Products Operating LLC
Mont Belvieu Complex - Fracs IX and X
GHG Fugitive Emissions Calculations (EPNs FRAC F IX, X)

FACILITY NAME: Enterprise Products, Fracs IX and X, Mont Belvieu, Texas
AREA: Area 02126 - ISBL
COMPOSITION: Total VOC: Less Methane, Ethane & Inerts

FIN: **FRAC F IX**
EPN: **FRAC F IX**

METHODOLOGY USED: SOCMI w/o Ethylene
CONTROL EFFICIENCY: 28LAER w/ flanges monitored as valves

COMPONENT	As-Built COMP. COUNT	HOURS SERVICE (hrs)	CH4 PERCENT (%)	EMISSION FACTOR (lb/hr-comp.)	PERCENT REDUCTION (%)	EMISSIONS (ton/yr)
VALVES						
GAS/VAPOR	636	8760	0	0.0089	97	0.00
GAS/VAPOR (Fuel Gas)	268	8760	98	0.0089	97	0.31
LIGHT LIQUID	1286	8760	0	0.0035	97	0.00
LIGHT LIQUID	539	8760	25	0.0035	97	0.06
HEAVY LIQUID	0	8760	0	0.0070	30	0.00
PUMPS						
DOUBLE MECH. SEAL	9	8760	0	0.0386	100	0.00
LIGHT LIQUID	0	8760	0	0.0386	93	0.00
HEAVY LIQUID	0	8760	0	0.0161	0	0.00
FLANGES						
GAS/VAPOR	460	8760	0	0.0029	97	0.00
GAS/VAPOR (Fuel Gas)	349	8760	98	0.0029	97	0.13
LIGHT LIQUID	3130	8760	0	0.0005	97	0.00
LIGHT LIQUID (Y-Grade)	1600	8760	25	0.0005	97	0.03
HEAVY LIQUID	0	8760	0	0.00007	0	0.00
OPEN-ENDED LINES	1444	8760	0	0.004	100	0.00
RELIEF VALVES w/RD	39	8760	0	0.2293	100	0.00
COMPRESSORS	2	8760	0	0.5027	100	0.00
SAMPLE CONNECTIONS	0	8760	0	0.033	97	0.00
OTHER	300	8760	0	0.000265	97	0.00
					TOTAL	0.53

FIN: **FRAC F X**
EPN: **FRAC F X**

METHODOLOGY USED: SOCMI w/o Ethylene
CONTROL EFFICIENCY: 28LAER w/ flanges monitored as valves

COMPONENT	As-Built COMP. COUNT	HOURS SERVICE (hrs)	VOC PERCENT (%)	EMISSION FACTOR (lb/hr-comp.)	PERCENT REDUCTION (%)	(ton/yr)
VALVES						
GAS/VAPOR	636	8760	0	0.0089	97	0.00
GAS/VAPOR (Fuel Gas)	268	8760	98	0.0089	97	0.31
LIGHT LIQUID	1286	8760	0	0.0035	97	0.00
LIGHT LIQUID	539	8760	25	0.0035	97	0.06
HEAVY LIQUID	0	8760	0	0.0070	30	0.00
PUMPS						
DOUBLE MECH. SEAL	9	8760	0	0.0386	100	0.00
LIGHT LIQUID	0	8760	0	0.0386	93	0.00
HEAVY LIQUID	0	8760	0	0.0161	0	0.00
FLANGES						
GAS/VAPOR	460	8760	0	0.0029	97	0.00
GAS/VAPOR (Fuel Gas)	349	8760	98	0.0029	97	0.13
LIGHT LIQUID	3130	8760	0	0.0005	97	0.00
LIGHT LIQUID (Y-Grade)	1600	8760	25	0.0005	97	0.03
HEAVY LIQUID	0	8760	0	0.00007	0	0.00
OPEN-ENDED LINES	1444	8760	0	0.004	100	0.00
RELIEF VALVES w/RD	39	8760	0	0.2293	100	0.00
COMPRESSORS	2	8760	0	0.5027	100	0.00
SAMPLE CONNECTIONS	0	8760	0	0.033	97	0.00
OTHER	300	8760	0	0.000265	97	0.00
					TOTAL	0.53

Note: Flanges will be monitored at the same leak definition as valves, so the valve credit will be used for flanges.
(1) All pumps are Dual Mechanical Seal
(2) Flange category is comprised of flanges and screwed connectors.
(3) There are 10 Sample Stations w/ regulated product. All components are less than 1/2", containing 40 points apiece.

Appendix B

RBLC Database Search Results

Appendix B

RBLC Database Search Results for GHG Emissions from Heaters

RBLCID	FACILITY NAME	COMPANY NAME	STATE	PERMIT DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Startup Heater	Natural gas	110.1 MMBTU/hr	Carbon Dioxide	good combustion practices	117 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Startup Heater	Natural gas	110.1 MMBTU/hr	Methane	good combustion practices	0.0023 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Startup Heater	Natural gas	110.1 MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Startup Heater	Natural gas	110.1 MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	638 TONS/YR
*MN-0085	ESSAR STEEL MINNESOTA LLC	ESSAR STEEL MINNESOTA LLC	MN	5/10/2012	INDURATING FURNACE	NATURAL GAS	542 MMBTU/H	Carbon Dioxide		710000 TON/YR

RBLC Database Search Results for GHG Emissions from Flares

RBLCID	FACILITY NAME	COMPANY NAME	STATE	PERMIT DATE	PROCESS NAME	PRIMARY FUEL	THROUGHPUT	POLLUTANT	CONTROL METHOD DESCRIPTION	EMISSION LIMIT
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	11/10/2011	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	COAL BED METHANE	25 MMBTU/H	Carbon Dioxide	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	3235 LB/MW-H
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	11/10/2011	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	COAL BED METHANE	25 MMBTU/H	Methane	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.06 LB/MW-H
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	11/10/2011	COAL BED METHANE-FIRED STANDBY FLARE W/PROPANE-FIRED PILOT	COAL BED METHANE	25 MMBTU/H	Nitrous Oxide (N2O)	GOOD COMBUSTION PRACTICES AND PROPER MAINTENANCE	0.05 LB/MW-H

Backup Information
Not Submitted to Agency

ENTERPRISE PRODUCTS OPERATING LLC

EHS&T PERMITTING PROJECT SIGN-OFF SHEET

This document is to be provided to the designated Responsible Official (RO) who will sign a permit application for the Company. By signing this document you are providing assurance to the RO that, to the best of your knowledge, the application has been prepared based on established Corporate policies and procedures and applicable regulatory and permitting requirements.

Project Name/Title	Fractionation Units IX and X	
Owner/Operator	Enterprise Products Operating LLC	
Facility Name	Mont Belvieu Complex	
Site Location (State/County/City)	Texas/Chambers County/Mont Belvieu	
Edwin Bergmann – Sr. Environmental Engineer	Edwin J. Bergmann	2/8/2013
Project Engineer Name/Title	Signature	Date

Summary: The attached document is the application to be submitted to EPA for a Greenhouse Gas (GHG) PSD air permit for proposed Fractionation Units IX and X to be constructed at the Mont Belvieu Complex. The TCEQ permit application for the same project was submitted on February 1, 2013. This GHG permit application is very similar to what was submitted to EPA for the GHG permit for the Eagleford Fractionation Units. The substantive differences are that the DIB unit included with the Eagleford permit application is not included here, and ethane and PSA flare gas recovery offgas are proposed as fuels in addition to natural gas. Fractionators IX and X are also based on a feed rate of 110,000 BBL/Day throughput.