Enterprise Products

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

ENTERPRISE PRODUCTS OPERATING LLC

December 18, 2012

Hand Delivered

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

RECEIVED
12 DEC 19 AM 10: 17
AIR PERMITS SECTION
6PD-R

RE: **Application for PSD Air Quality Permit**
Greenhouse Gas Emissions
Propane Dehydrogenation Unit
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 a Propane Dehydrogenation (PDH) Unit at our Mont Belvieu Complex. The primary product from the PDH Unit is propylene which will be shipped offsite via pipeline.

A State NSR and PSD permit application for other regulated pollutants is being submitted to TCEQ simultaneously. 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 me directly at (713) 381-5437.

Yours truly,

Christopher Benton
Manager, Environmental Permitting

/bjm
Enclosure

cc: Ms. Melanie Magee, EPA Region 6
Mr. Mathew Marra, Enterprise

Application for
Prevention of Significant Deterioration
Air Permit
Greenhouse Gas Emissions

Enterprise Mont Belvieu Complex
Propane Dehydrogenation Unit

Submitted by

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

December 2012

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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 a Propane Dehydrogenation (PDH) Unit at the Complex with a design propylene production capacity of 1.654 billion pound per year. A hydrogen byproduct will also be produced. Both the propylene and hydrogen products will be sent offsite via pipeline. The new facilities in the PDH Unit will include:

- Ten parallel catalytic reactors that convert propane feed to propylene,
- One Reactor Charge Heater,
- One Regeneration Air Heater,
- One Waste Heat Boiler with duct firing capability,
- Two Auxiliary Boilers,
- Two Regeneration Air Compressors,
- Two Regeneration Air Combustion Turbines,
- Cooling tower,
- Hydrogen Recovery (PSA) Unit,
- Ancillary tanks,
- Emergency pump engines,
- Process flare, and
- Wastewater treatment facilities.

A New Source Review permit amendment application has also been submitted to TCEQ for this project. The project triggers NNSR for VOC and PSD review for NO_x, CO, PM/PM_{10}/$PM_{2.5}$, SO_2, and H_2SO_4, for which TCEQ has approved permitting programs and PSD 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 for the GHG emissions associated with the project.

This document constitutes Enterprise's GHG PSD permit application for the modifications described above. Because 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 and modified 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		
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.: 713-381-5437	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: Propane Dehydrogenation Unit (PDH)		☒ 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: 01/01/2014	Projected Start of Operation Date: 07/01/2015	
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		
SIGNATURE: ______ *Original Signature Required*		
DATE: 12/18/2012		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date:	**12/18/2012**	
Company: **Enterprise Products Operating LLC**			
RN: **102323268**	Facility Location: **10207 FM 1942**		
City: **Mont Belvieu**	County: **Chambers**		
Permit Unit I.D.: **PDH Unit**	Permit Name: **PDH Unit**		
Permit Activity: New Source ___ Modification _X_			
Project or Process Description: **Construction of Propane Dehydrogenation (PDH) Unit**			

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]												1,289,149
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-Jan-14								contemporaneous period*			
Five years prior to start of construction	Date of last GHG PSD permit:						12-Oct-12					
Estimated start of operation	1-Jul-15											
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	NA	1,289,125
FNSR APPLICABLE? (yes or no)												Yes

*Slate is wiped clean by most recent GHG PSD permit issued for the source.

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	12/18/2012
Signature	Title	Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**GHG**	**Permit No.:**	**TBD**
Baseline Period:	**NA**	**Project Name:**	**PDH Unit**

					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	HR15.101	HR15.101	Combustion Unit Cap	TBD	-	-	1,281,586	-	1,281,586	0	1,281,586
2	HR15.103	DW37.101	Waste Heat Boiler Burner	TBD							
3	HR15.102		Regeneration Air Heater	TBD							
4	GT26.101A		Regen Air Comp. Gas Turbine A	TBD							
5	GT26.101B		Regen Air Comp. Gas Turbine B	TBD							
6	BO10.103A		Auxiliary Boiler A	TBD							
7	BO10.103B		Auxiliary Boiler B	TBD							
8	SK25.801	SK25.801	Process Flare, Routine	TBD	-	-	2,820.56		2,820.56	0.00	2,820.56
9	SK25.801	SK25.801	Process Flare, MSS	TBD	-	-	4,439.30		4,439.30	0.00	4,439.30
10	FUG-PDH	FUG-PDH	Process Fugitives	TBD	-	-	5.24		5.24	0.00	5.24
11	FUG-NGAS	FUG-NGAS	Nat. Gas Pipeline Fugitives	TBD	-	-	273.75		273.75	0.00	273.75
12	PM18.803	PM18.803	Fire Water Pump Engine	TBD	-	-	16.14		16.14	0.00	16.14
13	PM18.850C	PM18.850C	Raw Water Pump Engine	TBD	-	-	8.40		8.40	0.00	8.40
14											
15											
										Page Subtotal[9]:	**1,289,149**
										Project Total:	**1,289,149**

Table 3F
Project Contemporaneous Changes

Company: **Enterprise Products Operating LLC**

Criteria Pollutant: **GHG**

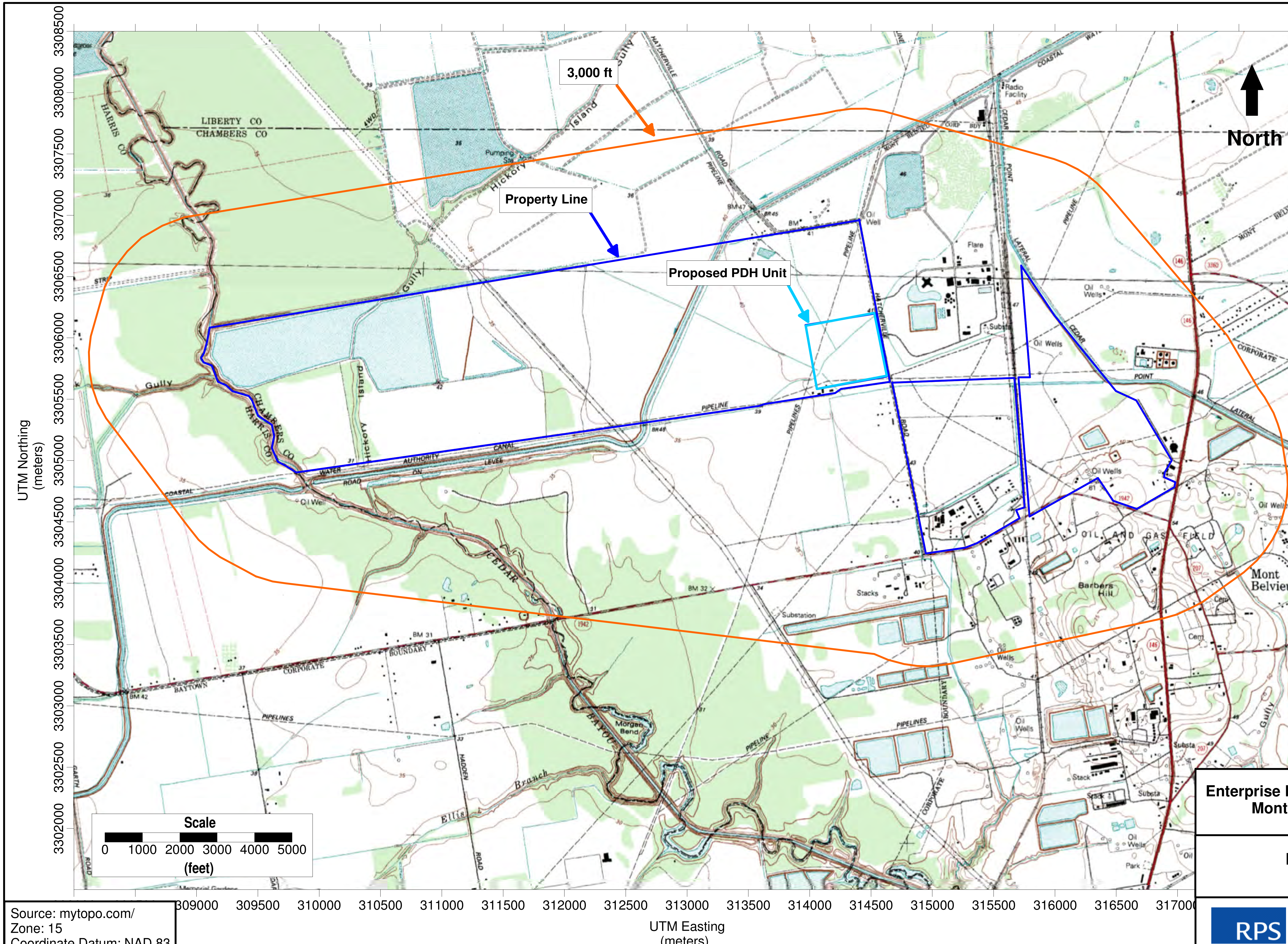
Permit Application No. **TBD**

No.	PROJECT DATE	EMISSION UNIT AT WHICH REDUCTION OCCURED FIN	EPN	PERMIT NUMBER	PROJECT NAME OR ACTIVITY	A PROPOSED EMISSIONS (tons / year)	B BASELINE EMISSIONS (tons / year)	C DIFFERENCE (A-B) (tons / year)	CREDITABLE DECREASE OR INCREASE (tons / year)
1	July 1, 2015	HR15.101	HR15.101	TBD	PDH Unit	1,281,586	0	1,281,586	1,281,586
2	July 1, 2015	HR15.103	DW37.101	TBD	PDH Unit				
3	July 1, 2015	HR15.102		TBD	PDH Unit				
4	July 1, 2015	GT26.101A		TBD	PDH Unit				
5	July 1, 2015	GT26.101B		TBD	PDH Unit				
6	July 1, 2015	BO10.103A		TBD	PDH Unit				
7	July 1, 2015	BO10.103B		TBD	PDH Unit				
8	July 1, 2015	SK25.801	SK25.801	TBD	PDH Unit	2,821	0	2,821	2,821
9	July 1, 2015	SK25.801	SK25.801	TBD	PDH Unit	4,439	0	4,439	4,439
10	July 1, 2015	FUG-PDH	FUG-PDH	TBD	PDH Unit	5	0	5	5
11	July 1, 2015	FUG-NGAS	FUG-NGAS	TBD	PDH Unit	274	0	274	274
12								0	0
13								0	0
14								0	0
15								0	0
16								0	0
17								0	0
18								0	0
19								0	0
20								0	0
								PAGE SUBTOTAL:	1,289,125
	Summary of Contemporaneous Changes							TOTAL :	**1,289,125**

12/18/2012

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 modified facilities is presented in Figure 3-2.

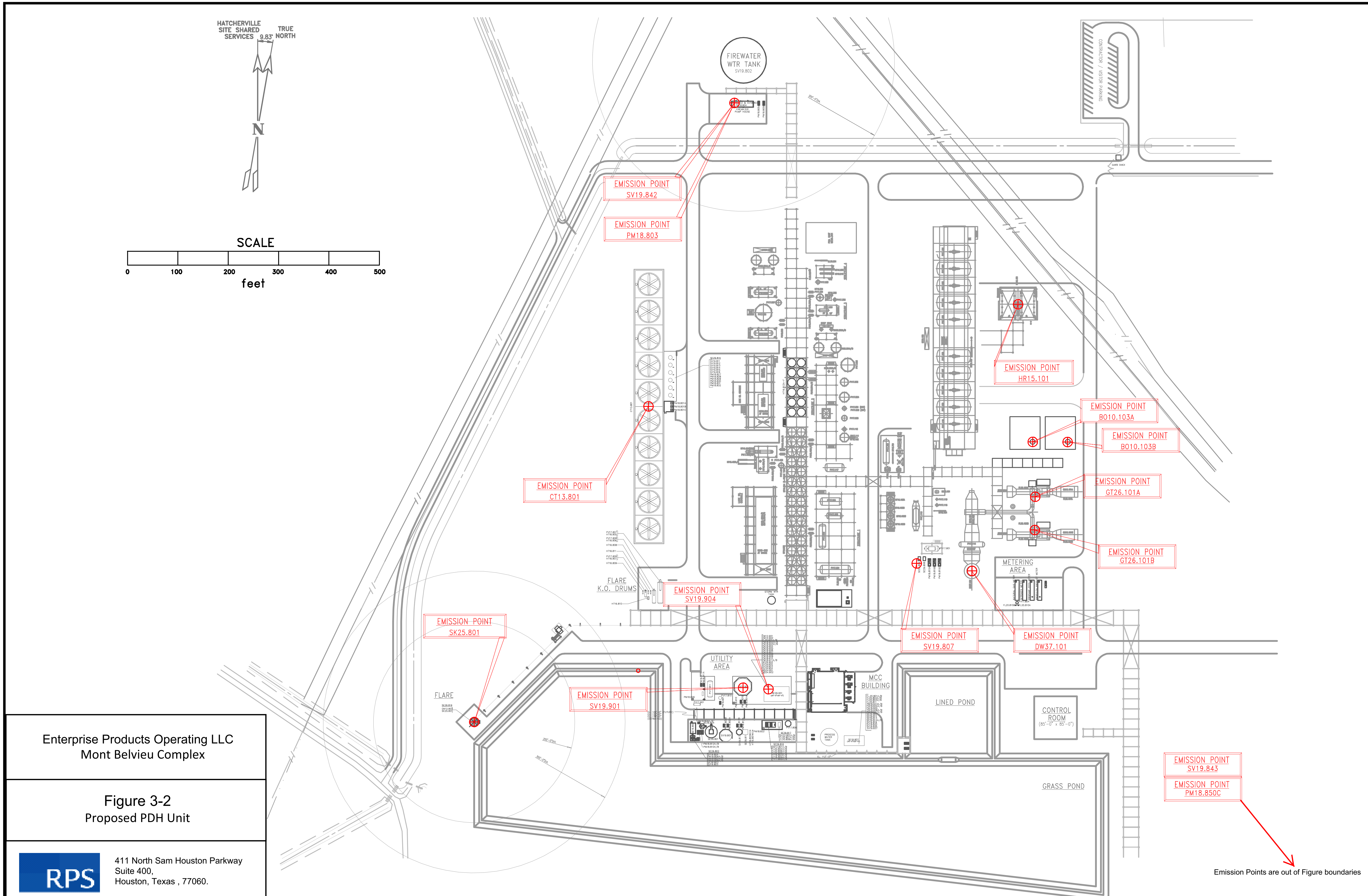


Source: mytopo.com/
Zone: 15
Coordinate Datum: NAD 83

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 PDH Unit

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

Section 4
Process Description

A brief overview of the process is included below, and a simplified process flow diagram of the PDH process is shown in Figure 4-1. A block flow diagram of the Waste Heat Boiler is shown in Figure 4-2.

The proposed PDH Unit will convert propane to propylene over a catalyst. The unconverted propane is recycled so that propylene is the only net product. A hydrogen byproduct is also produced.

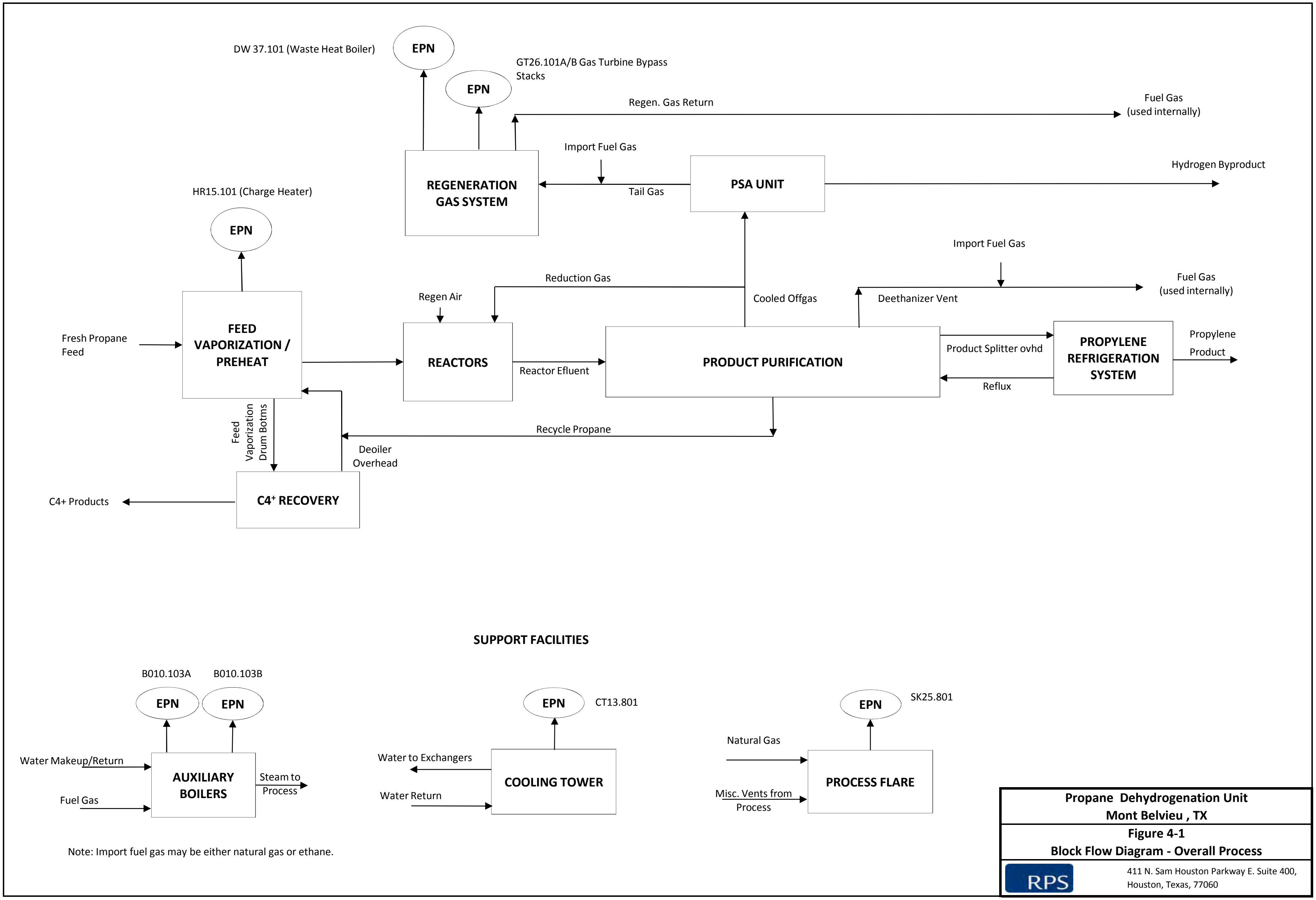
Operating conditions are selected to optimize the relationships among selectivity, conversion, and energy consumption. Side reactions occurring simultaneously with the main reaction cause the formation of some light and heavy hydrocarbons as well as the deposition of coke on the catalyst.

The process takes place in fixed-bed reactors that operate on cyclic basis. In one complete cycle, hydrocarbon vapors are dehydrogenated; the reactor is then purged with steam and blown with air to reheat the catalyst and burn off the small amount of coke that is deposited on the catalyst during the reaction cycle. These steps are followed by an evacuation and reduction, and then another cycle is begun.

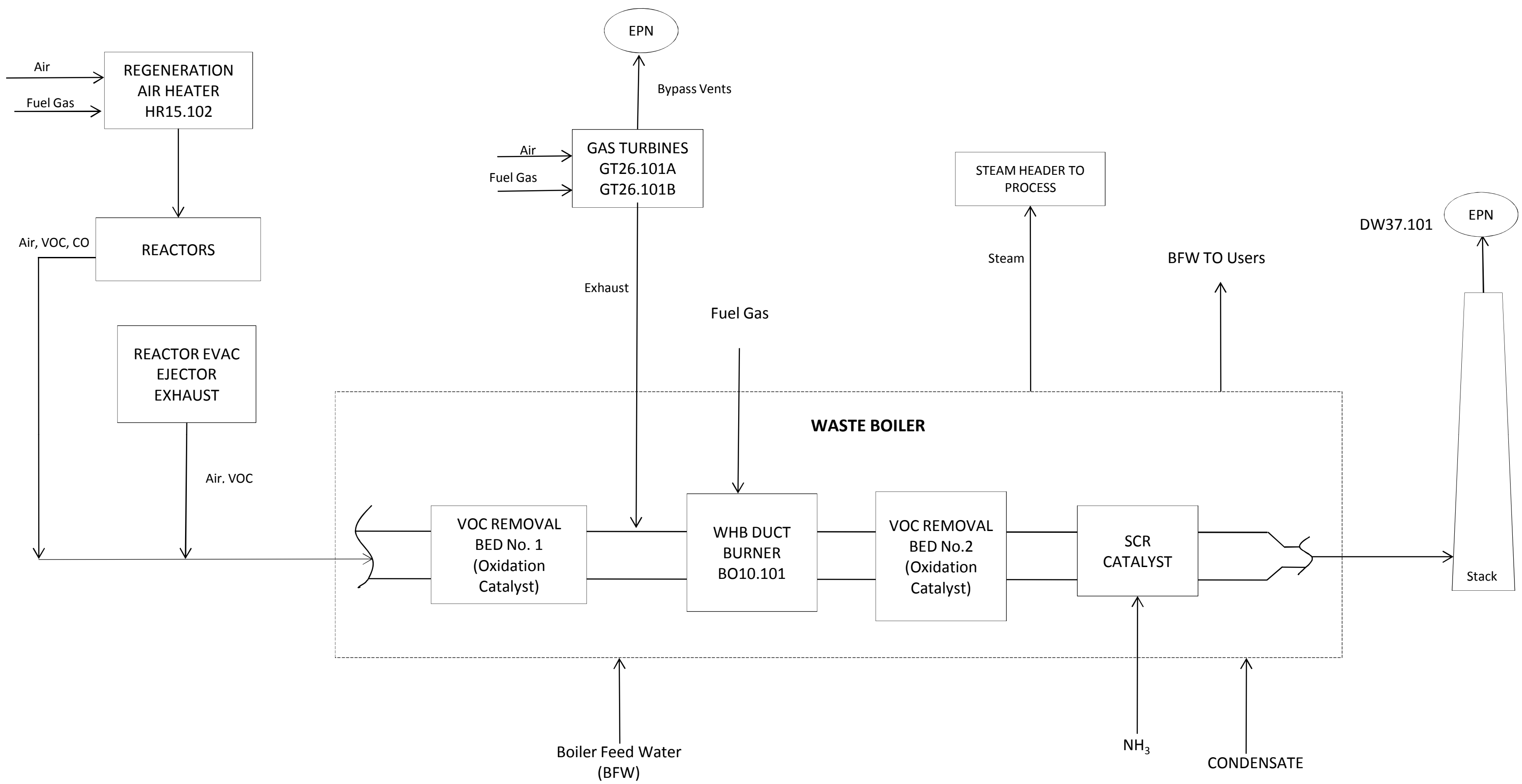
A key feature of the process is that the heat absorbed during the endothermic dehydrogenation period is obtained by the adjustment of the air and hydrocarbon inlet temperatures and by the oxidation of the coke.

The low temperature recovery area, product purification, and refrigeration systems have been integrated to optimize energy efficiency. The design contains:

- Cascade propylene and ethylene refrigeration system.
- A high efficiency cold box design that minimizes equipment count and refrigerant compressor power demand.
- A low pressure Deethanizer that eliminates the need for feed pumps.
- A low pressure Product Splitter integrated with the propylene refrigeration system.



Propane Dehydrogenation Unit
Mont Belvieu , TX
Figure 4-1
Block Flow Diagram - Overall Process



Note: Fuel gas may be natural gas, ethane, or process offgas.

Propane Dehydrogenation Unit
Mont Belvieu , TX
Figure 4-2
Waste Heat Boiler Block Flow Diagram
RPS — 411 N. Sam Houston Parkway E. Suite 400, Houston, Texas, 77060

Section 5
Emission Rate Basis

This section contains a description of the increases in GHG emissions from the proposed 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 Combustion Units

The emissions calculations presented in Table A-1 of Appendix A identify all fuels that could potentially be fired in each combustion unit. However, the emissions calculations are based on firing the primary fuel for each unit, with all available Deethanizer Offgas and PSA Tail Gas fired, and the balance of the fuel requirements made up by ethane and natural gas. Because these fuels have different CO_2 emission factors, the actual annual emission rate from each unit will depend on the amount of each fuel fired. The maximum individual unit emission rates shown in Table 5-1 are based on firing all available "worst case" fuel in each unit. As a result, the sum of the individual unit emission limits exceeds the total emissions that are possible from the plant as a whole. Thus, in addition to the individual emission limits, Enterprise is proposing overall combustion unit caps for each GHG pollutant and total CO_2e. This caps, calculated in Table A-1, include all GHGs and CO_2e from the Reactor Charge Heater, the WHB Stack (WHB includes Gas Turbines, Regeneration Air Heater, Reactor VOC, Coke Burn, and WHB Duct Burners), and the Auxiliary Boilers.

5.1.1 Reactor Charge Heater

The Reactor Charge Heater (HR15.101) will be fired primarily with Deethanizer Offgas. The heater will also be capable of burning ethane and natural gas. Under normal conditions, sufficient Deethanizer Offgas will be generated within the process to provide all required fuel for the heater. Deethanizer Offgas and ethane result in higher CO_2 emissions than natural gas; therefore, the GHG emissions calculations for this unit are based on firing Deethanizer Offgas. As can be seen from the emission factors presented in Table A-1 of Appendix A, Deethanizer Offgas and ethane, have virtually identical GHG emission factors (lb/mmBtu basis). Annual GHG emissions were calculated based on the maximum fuel firing rate of the heater occurring continuously (8,760 hr/yr) all year. CO_2 emissions were calculated based on the carbon content of the Deethanizer Offgas using Equation C-5 in 40 CFR Part 98, Subpart 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, Subpart C.

5.1.2 Waste Heat Boiler (WHB)

Several facilities will contribute GHG emissions to the WHB. These include the Regeneration Air Heater (HR15.102) combustion products, VOC from the Reactors that is converted to CO_2 by oxidation catalyst beds, carbon from decoking of the reactor catalysts that is converted to CO_2 by the oxidation catalyst beds, Regeneration Air Gas Turbine (GT26.101A and GT26.101B) combustion products, and WHB Duct Burners (HR15.103) combustion products. The Regeneration Air Heater will primarily burn PSA Tail Gas and ethane or natural gas, but will also be capable of burning Deethanizer Offgas. The Gas Turbines will be fired exclusively with natural gas, and the WHB Duct Burners will be fired primarily with natural gas and ethane but will be capable of firing Deethanizer Offgas and PSA Tail Gas. LTRU Offgas can be burned in the Regeneration Air Heater and WHB Duct Burners; however, this only occurs when the PSA Unit down, which is an upset condition. LTRU Offgas is primarily hydrogen, which results in less emissions than other fuels. Under normal operating conditions, this stream is the feed to the PSA Unit. For these reasons, none of the emission limits are based on combusting LTRU Offgas. The calculations of the emissions from each facility that will exhaust through the WHB Stack are described below.

5.1.2.1 Combustion Turbines

There will be two combustion turbines constructed for the project, (GT26.101A and GT26.101B). The turbines will be used to compress the air used for reactor regenerations. Natural gas will be the only fuel fired in the combustion turbines. Annual GHG emissions were calculated based on the projected annual average fuel firing rate of each turbine. CO_2 emissions were calculated based on the carbon content of the natural gas using Equation C-5 in 40 CFR Part 98, Subpart 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, Subpart C.

5.1.2.2 Regeneration Air Heater

The Regeneration Air Heater (HR15.102) will normally be fired with all available PSA offgas with the remainder of the heat input from either ethane or natural gas. Deethanizer Offgas may also be fired in the heater. Annual GHG emissions were calculated based on the projected annual average fuel firing rate of the heater. The emissions are base on burning all available PSA Tail Gas and the balance of the fuel being Deethanizer Offgas and Ethane. CO_2 emissions were calculated based on the carbon content of each fuel using Equation C-5 in 40 CFR Part 98, Subpart 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, Subpart C.

5.1.2.3 WHB Duct Burner

The WHB will include a supplemenatally fired duct burner (HR15.103) that will be fired as needed to provide for plant steam requirements. The duct burner will be fired primarily with ethane or natural gas, but will also be capable of firing Deethanizer Offgas and PSA Tail Gas. Maximum emissions occur from firing Deethanizer Offgas and/or ethane; therefore, the emission limits were calculated based on firing Deethanizer Offgas. Annual GHG emissions were calculated based on the projected annual average firing rate of the duct burner. CO_2 emissions were calculated based on the carbon content of the fuels using Equation C-5 in 40 CFR Part 98, Subpart 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, Subpart C.

5.1.2.4 Reactor Air Effluent and Ejector

VOC from the reactors is carried over in the Regeneration Air that enters the WHB. This VOC is treated in a catalytic oxidation bed that converts the VOC to CO_2. The catalytic oxidation bed will be designed with a VOC destruction efficiency of at least 98.2%. CO_2 emissions were conservatively calculated assuming 100% destruction (conversion to CO_2). Stoichiometrically, production of CO_2 from the oxidation of the VOC in the oxidation catalyst bed is identical to the production of CO_2 from combustion of carbon fuels. Therefore, CO_2 emissions were calculated based on the carbon content of the VOC using Equation C-5 in 40 CFR Part 98, Subpart C.

5.1.2.5 Decoke

CO_2 emissions will be produced during periodic oxidation of the coke that builds up on the catalyst. The emission rate is based on an estimate from the engineering design firm for the project. These emissions are part of the Reactor Regeneration Effluent that is a contributor to the combined WHB stack exhaust.

5.1.3 Auxiliary Boilers

The two Auxiliary Boilers (BO10.103A and BO10.103B) will normally operate at a very low standby rate and will only be fully fired to provide steam when the primary units are down. The Auxiliary Boilers will be fired primarily with ethane or natural gas, but will also be capable of firing Deethanizer Offgas and PSA Tail Gas. Maximum emissions occur from firing Deethanizer Offgas and/or ethane; therefore, the emission limits were calculated based on firing Deethanizer Offgas. Annual GHG emissions were calculated based on firing the boilers at full load for 310 hour/yr each and at standby rates for the remainder of the year. CO_2 emissions were calculated based on the carbon content of the fuels using Equation C-5 in 40 CFR Part 98, Subpart 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, Subpart C.

5.1.4 Combustion Unit Emissions Caps

The combustion unit emissions caps which include all emissions from the facilities described above were calculated based on the total combined annual heat input of all units. The calculations of the caps are shown in Table A-1. The firing rates of each fuel used to provide the total plant heat input were based on firing all produced Deethanizer Offgas and PSA Tail Gas, firing natural gas in the combustion turbines, and the balance of the heat input being provided by ethane. CO_2 emissions were then calculated based on the carbon content of each 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, Subpart C. The CO_2 from decoking and the oxidation of the Reactor VOC calculated as described in Sections 5.1.2.4 and 5.1.2.5 were also added to the cap since this CO_2 will be emitted through the WHB Stack.

5.2 Flare Emissions

The new PDH Unit will have process vents that will be routed to a new flare (SK25.801) for control. These process 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. The calculations are shown in Table A-3.

5.3 Process Fugitive Emissions

Fugitive (equipment leak) emissions of methane will occur from the new natural gas and process gas piping components (FUG-NGAS and FUG-PDH). The 28LAER leak detection and repair (LDAR) program will be applied to the new VOC components associated with the PDH 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 natural gas and process gas. The calculations are shown in Table A-4.

5.4 Diesel Engines

There will be two diesel fired engines (PM18.803 and PM18.850C) used for emergency purposes only. The engines will be used to drive fire water and raw water pumps. The permitted emissions are based only on firing of the engines as required for scheduled testing to insure operability, which will not exceed 52 hours per year each. Emissions were calculated from emission factors for No. 2 distillate fuel in Tables C-1 and C-2 of Appendix A to 40 CFR Part 98, Subpart C. The calculations are shown in Table A-5.

Table 5-1 Proposed GHG Emission Limits

EPN	Description	CO_2 Emission Rate (tpy)	CH_4 Emission Rate (tpy)	N_2O Emission Rate (tpy)	CO_2e Emission Rate (tpy)
Individual Combustion Unit Limits					
HR15.101	Reactor Charge Heater	280,168	12.99	2.54	281,229
DW37.101	Waste Heat Boiler Burner	19,522	0.98	0.20	19,603
	Regeneration Air Heater	650,704	23.89	4.25	652,523
	Regen Air Comp. Gas Turbine A	124,897	2.32	0.23	125,018
	Regen Air Comp. Gas Turbine B	124,897	2.32	0.23	125,018
	VOC from Reactors	5,580	-	-	5,580
	Coke Burn	60,000	-	-	60,000
BO10.103A	Auxiliary Boiler A	16,321	0.82	0.16	16,389
BO10.103B	Auxiliary Boiler B				
Combustion Unit Cap		1,276,248	64.31	12.86	1,281,586
Other					
FUG-PDH	Process Fugitives	-	0.25	-	5
FUG-NGAS	Nat. Gas Pipeline Fugitives	-	13.04	-	274
SK25.801	Process Flare, Routine	2,818	0.04	0.01	2,821
	Process Flare, MSS	4,426	0.16	0.03	4,439
PM18.803	Fire Water Pump Engine	16	0.0007	0.0001	16
PM18.850C	Raw Water Pump Engine	8	0.0003	0.0001	8
Total GHG Emissions		**1,283,517**	**77.79**	**12.90**	**1,289,149**

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 the following:

- Reactor Charge Heater (HR15.101)
- Regeneration Air Heater (HR15.102)
- Waste Heat Boiler Duct Burner (HR15.103)
- Two Combustion Turbines (GT26 101A and GT26 101A B),
- Two Auxiliary Boilers (BO10.103A and BO10.103B)
- Process Fugitives (FUG-PDH and FUG-NGAS)
- Process Flare (SK25.801)
- Two Emergency Use Diesel Engines (PM18.803 and PM18.850C).

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* (March 2011), 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 Reactor Charge Heater

6.1.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the Mont Belvieu Complex, the proposed heaters will be designed to achieve high thermal efficiencies, which minimize GHG emissions. The Reactor Charge Heater will be designed to achieve a 90% thermal efficiency. These and other potentially applicable technologies to minimize GHG emissions from the heater include the following:

- Periodic Tune-up – Periodically tune-up of the heater 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 excess air on a continuous basis for optimal efficiency.
- Waste Heat Recovery – Use of heat recovery from the heater exhaust to preheat the heater combustion air or other streams.
- 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 control 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. Carbon capture and sequestration (CCS) is not considered to be a viable alternative for controlling GHG emissions from 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 and Fuel Control (5 - 25%),
- Periodic tune-up (up to 10% for boilers; information not found for heaters), and
- Waste heat recovery (variable).

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 and fuel 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.

Heat recovery involves the use of heat exchangers to transfer the excess heat that may be contained in one process or product stream to pre-heat another stream. 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. The Charge Heater will be designed for 90% thermal efficiency, and additional heat recovery is not practical. However, heat exchange coils will be included in the convection section to pre-heat Waste Heat Boiler feedwater.

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 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* (March 2011). 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.

Enterprise has performed an order of magnitude cost analysis for CCS applied to the combustion units 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 $119,000,000 per year all combustion units included at the proposed plant. The estimated total capital cost of the PDH unit is $1,300,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of about $123,000,000. Thus, the annualized cost of CCS would be about the same as the cost of the PDH plant alone; 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 facilities. 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, 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 heater allows them to be designed to achieve "near best" thermal efficiency.

Air and 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 controls are used to optimize these parameters and maximize the efficiency of the combustion process.

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

- Preventive maintenance check of fuel gas flow meters annually,
- Preventive maintenance check of excess oxygen 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.

Use of Low Carbon Fuel. Several low carbon fuels are potentially available for use in the PDH plant combustion units. The discussion below applies to all combustion units within the proposed PDH Unit.

Hydrogen. Hydrogen is a byproduct of the proposed PDH process. The PDH Unit will include a PSA Unit that will purify the hydrogen byproduct. Enterprise's business plan calls for selling the hydrogen as a product; therefore, it is not available for use as a fuel at the plant. The most common industrial use of hydrogen in the Gulf Coast area is for the desulfurization of crude oil in petroleum refineries. Hydrogen for this use is typically produced at refineries in steam methane reformers (SMR), which produce hydrogen from methane, producing a large CO_2 stream that is exhausted to the atmosphere. Thus, the hydrogen product from the proposed PDH Unit will displace an equivalent amount of hydrogen production from refinery SMRs, eliminating the associated CO_2 emissions. Thus, although using the hydrogen byproduct as fuel within the PDH Unit would reduce CO_2 emissions from the proposed plant, there would be a corresponding increase in CO_2 emissions from the production of hydrogen elsewhere, resulting in no net "global" reduction of CO_2 emissions. Unlike criteria pollutants, GHG emission impacts are "global," and there is no benefit in simply displacing the emissions to another location. For this reason together with Enterprise's business plan to produce hydrogen as a marketable product, use of the hydrogen byproduct as a fuel at the PDH Unit is not considered to be a viable option for reducing global CO_2 emissions.

PSA Tail Gas. Tail Gas from the PSA Unit will contain a significant fraction (about 60% by volume) of hydrogen. The CO_2e emission factor for this Tail Gas will average about 96 lb/mmBtu, compared to about 118 lb/mmBtu for the natural gas that is available for use at the plant. About 2,200,000 mmBtu/yr of PSA Tail gas will be produced at the PDH plant capacity. This corresponds to a potential reduction in CO2e emissions of about 23,000 tpy compared to firing an equivalent amount of natural gas.

Deethanizer Offgas. Deethanizer Offgas will also be produced in the PDH Unit. This process gas, which is primarily ethane and ethylene, has a CO_2e emission factor of about 131 lb/mmBtu, which is only about 11% higher than natural gas. Thus this fuel is also considered a low carbon fuel when compared to liquid and solid fuels. If this offgas is not burned as fuel at the PDH Unit, the only other alternative means of disposal is destruction in a flare, which would result in the same amount of CO_2e emissions in addition to the CO_2e emissions from the natural gas that would replace it as a fuel. As such, use of the Deethanizer Offgas as fuel is an effective means of reducing overall plant GHG emissions compared to the alternative of flaring the gas.

Ethane. Ethane is also an available fuel for the PDH Unit. 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 PDH Unit). 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, which is about the same as the Deethanizer Offgas that will be produced in the PDH Unit. 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.

Natural Gas. Other than PSA Tail Gas, natural gas is the lowest carbon fuel available for use in the proposed heater. 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.

6.1.5 Step 5 – Selection of BACT

Air and fuel controls, efficient heater design, and tune-ups performed as needed are currently utilized on 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 Charge Heater and are thus part of the selected BACT. These technologies and additional BACT practices proposed for the Charge Heater are listed below:

- Use of a combination of low carbon fuels. A combination of PSA Tail Gas, Deethanizer Offgas, ethane, and natural gas will be fired in the proposed PDH Unit combustion units. This will result in an overall CO_2e emission rate of about 125 lb/mmBtu of fuel burned. This emission rate is comparable to burning 100% natural gas, and results in lower "global" CO_2e emissions compared to burning 100% natural gas and disposing of the offgases by other methods.
- Determine CO_2e emissions from the Reactor Charge Heater 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 evenly heat the propane feed and reduce heat loss. Insulating material, such as ceramic fiber blankets of various thickness and density, will be used where feasible on all heater surfaces.
- Demonstrate 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 accepted API methods. Charge Heater efficiency of greater than 85% will be maintained on a 12-month rolling average basis, excluding malfunction and maintenance periods.
- The heater will include heat exchange coils in the convection section to pre-heat the boiler feedwater used in the Waste Heat Boiler.
- Install, utilize, and maintain an automated air and fuel control system to maximize combustion efficiency of the heater.
- Clean heater burner tips and convection tubes as needed.

- Calibrate and perform preventive maintenance on the fuel flow meter once per year and excess oxygen analyzer once per quarter.

6.2 Regeneration Air Heater

6.2.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the Mont Belvieu Complex, the proposed heaters are designed to achieve high thermal efficiencies, which minimize GHG emissions. The Regeneration Air Heater will utilize duct burners, and the heater will be designed to maximize thermal efficiency. These and other potentially applicable technologies to minimize GHG emissions from the heater include the following:

- Periodic Tune-up – Periodically tune-up of the heater to maintain optimal thermal efficiency.
- Heater Design – Good heater design utilizing refractory to maximize thermal efficiency,
- Waste Heat Recovery – Use of heat recovery from the heater exhaust and a waste heat boiler to produce steam for use at the site.
- Use of Low Carbon Fuels – Use of low carbon fuels at the plant were addressed in Section 6.1 and are not addressed separately for the Regeneration Air Heater.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2 (This option is evaluated in detail in Section 6.1.4 for the plant as whole and was eliminated based on cost and is thus not addressed further in this section).

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 control 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.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

6.2.3 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:

- Waste heat recovery (variable),
- Heater Design (up to 10%), and
- Periodic tune-up (up to 10% for boilers; information not found for heaters).

Air is heated by the Regeneration Air Heater duct burners and used to regenerate the catalyst in the reactors. The hot air from the reactors contains a large amount of usable heat energy, and the proposed process is designed to recover and use this heat by routing the hot air through the Waste Heat Boiler which provides the plant steam requirements. This is discussed in more detail in Section 6.3.

Good heater design 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.

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

Heater Design. New heaters can be designed with efficient burners, more efficient heat transfer, 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 heater allows it to be designed to achieve “near best” thermal efficiency.

Periodic Heater Tune-ups. Periodic tune-ups of the heater 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.

6.2.5 Step 5 – Selection of BACT

Efficient heater design and tune-ups performed as needed are currently utilized on 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 Regeneration Air Heater and are thus part of the selected BACT. These technologies and additional BACT practices proposed for the heater are listed below:

- Use of a combination of low carbon fuels. A combination of PSA Tail Gas, Deethanizer Offgas, ethane, and natural gas will be fired in the proposed PDH Unit combustion units, including the Regeneration Air Heater, to maintain a plantwide CO_2e emission rate of about 125 lb/mmBtu.
- Determine CO_2e emissions from the Regeneration Air Heater based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Good heater design to maximize heat transfer efficiency and reduce heat loss. Insulating material, such as ceramic fiber blankets of various thickness and density, will be used where feasible on all heater surfaces.
- Route hot spent regenerator air through Waste Heat Boiler to recover heat for steam production.
- Install, utilize, and maintain an automated fuel control system to maximize combustion efficiency of the heater.
- Clean heater burner tips as needed.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year.

6.3 Waste Heat Boiler

6.3.1 Step 1 – Identification of Potential Control Technologies

The Waste Heat Boiler (WHB) is the key heat energy efficiency feature of the proposed PDH Unit design that will allow the plant to produce propylene with up to one-third less fuel consumption than other production processes. The combustion products from the Regeneration Air Heater and the Regeneration Air Compressor Combustion Turbines is routed through the WHB to produce steam that is used internally in the PDH Unit. The WHB will include a gas-fired duct burner that will be used for startup of the WHB and to provide supplemental heat as needed to meet plant steam demand. These and other potentially applicable technologies to minimize GHG emissions from the boilers include the following:

- Good combustion practices via improved process controls.
- Boiler Design – Good boiler design to maximize thermal efficiency,
- Routine Boiler Maintenance - Periodically tune-up the boiler to maintain optimal thermal efficiency.
- Waste Heat Recovery - The proposed boiler is a waste heat recovery unit that will obtain most of its required heat energy from waste heat.
- Use of Low Carbon Fuels – Use of low carbon fuels at the plant were addressed in Section 6.1 and are not addressed separately for the WHB Duct Burners.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2 (This option is evaluated in detail in Section 6.1.4 for the plant as whole and was eliminated based on cost and is thus not addressed further in this section).

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 control 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.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- Waste Heat Recovery has primary energy source (>90%),
- Boiler Design (up to 26%), and
- Routine planned maintenance tune-up (up to 10%).

Hot exhaust from the regeneration of the reactors and from the Regeneration Air Compressor Turbine exhaust contains sufficient waste heat to provide over 90% of the heat input normally required for steam produced in the WHB and is thus considered the most effective means of reducing GHG emissions by eliminating the combustion of fuel that would otherwise be required.

Good boiler design 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 boiler designs.

Heat recovery involves the use of economizers to transfer the excess heat from the boiler flue gases to the boiler feed water streams. Pre-heating of boiler feed water stream in this manner reduces the heat requirement of the boilers.

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

Waste Heat Recovery. Rather than increasing boiler efficiency, this technology reduces potential GHG emissions by reducing the required WHB duct burner firing rate, which can substantially reduce overall plant energy requirements. Over 800 mmBtu/hr of waste heat energy from the Reactor Regeneration Air Exhaust and Compressor Combustion Turbine Exhaust will be recovered in the WHB and used to produce steam. On an annual average basis, the supplemental WHB duct burner will only need to be fired at a rate of about 30 mmBtu/hr. Thus, over 95% of the heat energy required for the PDH Unit steam demand will be provided from waste heat.

Boiler Design. New boilers can be designed with efficient burners, more efficient heat transfer, state-of-the-art refractory and insulation materials in the boiler walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. The function and near steady state operation of the boilers allows them to be designed to achieve “near best” thermal efficiency.

Periodic Boiler Maintenance Tune-ups. Periodic tune-ups of the boilers include:

- Preventive maintenance check of fuel gas flow meters annually,

- 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.

6.3.5 Step 5 – Selection of BACT

Use of the proposed WHB itself is the primary GHG BACT feature of the PDH Unit. Air/fuel controls, efficient boiler design, and tune-ups performed as needed will also be included to maximize efficiency and thus reduce GHG emissions. These technologies and additional BACT practices proposed for the boilers are listed below:

- Use of waste heat to provide over 95% of the WHB heat energy requirements.
- Use of low carbon fuel. A combination of PSA Tail Gas, Deethanizer Offgas, ethane, and natural gas will be fired in the proposed PDH Unit combustion units, including the WHB Duct Burner, to maintain a plantwide CO_2e emission rate of about 125 lb/mmBtu.
- Determine CO_2e emissions from the Waste Heat Boiler based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Good boiler design to maximize heat transfer efficiency and to reduce heat loss.
- Install, utilize, and maintain an automated fuel control system to maximize combustion efficiency on the boilers.
- Clean heater burner tips and convection tubes as needed.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year.
- Use of boiler feedwater pre-heated by the economizer in the Reactor Charge Heater.

6.4 Auxiliary Boilers

6.4.1 Step 1 – Identification of Potential Control Technologies

The Auxiliary Boilers will be designed to maximize thermal efficiency and will be designed to operate in a very low (about 3% of full load firing rate) standby rate when not in use. These and other potentially applicable technologies to minimize GHG emissions from the boilers include the following:

- Good combustion practices that include; improved process controls, reducing flue gas quantities, and reducing excess air.
- Boiler Design – Good boiler design to maximize thermal efficiency,

- Low standby operation,
- Routine boiler maintenance - Periodically tune-up of the boilers to maintain optimal thermal efficiency.
- Use of Low Carbon Fuels – Use of low carbon fuels at the plant were addressed in Section 6.1 and are not addressed separately for the Auxiliary Boilers.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2 (This option is evaluated in detail in Section 6.1.4 for the plant as whole and was eliminated based on cost and is thus not addressed further in this section).

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 control 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.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.
The two auxiliary boilers, although of a size sufficient enough to consider use of a carbon capture and sequestration (CCS) system, will only be in operation for short periods of time during the year as backup boilers to the waste heat boiler. This makes the carbon capture and sequestration process not technically feasible for the two auxiliary boilers. A cost analysis for use of CCS at the proposed plant, included in Section 6.1, has also shown that CCS is not cost effective.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- Low Standby Operating Rate,
- Boiler Design (up to 26%),
- Air and Fuel Control (1% improvement for each 15% less excess air),
- Routine planned maintenance tune-up (up to 10%).

The Auxiliary Boilers are projected to be needed for full use less than 4% (310 hr/yr) of the time; however, they must be kept in a hot standby condition to allow them to be brought on line quickly when needed. As such, the potential exists for the majority of the fuel consumption and resulting GHG emissions to occur from standby operation. As such, designing the boilers to operate at a very low standby firing rate is considered the most effective means of reducing GHG emissions.

Good boiler design, excess oxygen 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. Due to the very low expected usage rate, typical energy efficiency features used in boiler designs have minimal benefit for the proposed boilers.

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

Low Standby Operating Rate. Minimizing the standby firing rate to the maximum extent possible is the most effective means of controlling GHG emissions as this operating mode will occur over 96% of the time. There are no adverse environmental or economic impacts associated with this practice.

Boiler Design. New boilers can be designed with efficient burners, more efficient heat transfer, state-of-the-art refractory and insulation materials in the boiler walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. The function and near steady state operation of the boilers allows them to be designed to achieve "near best" thermal efficiency.

Air and 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 and fuel controls are used to optimizes these parameters and maximize the efficiency of the combustion process.

Periodic Boiler Maintenance Tune-ups. Periodic tune-ups of the boilers include:

- Preventive maintenance check of fuel gas flow meters annually,
- Preventive maintenance check of excess oxygen 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.

6.4.5 Step 5 – Selection of BACT

Designing the burners to operate at a low standby firing rate is proposed as the primary GHG BACT method for the Auxiliary Boilers. Air and uel controls and efficient boiler design, and tune-ups performed as needed are currently utilized on the existing fired equipment 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 boilers and are thus part of the selected BACT. These technologies and additional BACT practices proposed for the boilers are listed below:

- The boilers will be designed to be operated at a standby firing rate of 14 mmBtu/hr each, which is about 3.3% of the boiler capacities. Although standby operation will constitute over 96% of the operating hours, the low firing rate will result in total annual standby fuel usage and GHG emissions that are less than the total annual fuel usage and GHG emissions from full load operation.
- Use of low carbon fuel. A combination of PSA Tail Gas, Deethanizer Offgas, ethane, and natural gas will be fired in the proposed PDH Unit combustion units, including the Auxiliary Boilers, to maintain a plantwide CO_2e emission rate of about 125 lb/mmBtu.
- Determine CO_2e emissions from the Auxiliary Boilers based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Good boiler design to maximize heat transfer efficiency and to reduce heat loss.
- Install, utilize, and maintain an automated airand fuel control system to maximize combustion efficiency on the boilers.
- Clean heater burner tips and convection tubes as needed.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year and excess oxygen analyzers as needed.

6.5 Combustion Turbines

6.5.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the Mont Belvieu Complex, the proposed natural gas fired turbines are designed to achieve high thermal efficiencies, which minimize GHG emissions. The proposed new gas turbines are designed to maximize thermal efficiency. In addition, as described in Section 6.3, the turbines will exhaust into the WHB, where the heat in the exhaust will be recovered to the maximum extent practical to produce steam. These and other potentially applicable technologies to minimize GHG emissions from the gas turbines include the following:

- Good combustion practices via improved process controls and reducing excess air.
- Turbine Design – Good design to maximize thermal efficiency,
- Routine Maintenance - Periodically tune-up to maintain optimal combustion and thermal efficiency.
- Waste Heat Recovery – Use of heat recovery from the turbine exhausts in the WHB to produce steam for use at the site.
- Uses 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. (This option is evaluated in detail in Section 6.1.4 for the plant as whole and was eliminated based on cost and is thus not addressed further in this section).

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 control 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.

Waste heat recovery from the turbine exhaust is included in the process design and has been addressed in Section 6.3 of the BACT analysis for the WHB and is not address further in this section.

6.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible.

6.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- Use of low carbon alternative fuels,

- Turbine Design,
- Good Combustion Practices,
- Routine planned maintenance tune-up (up to 10%).

Natural gas is the lowest carbon fuel available for use in the proposed turbines. Use of other gaseous fuels are not recommended by the turbine vendor.

Good turbine design, good combustion practices 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.

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

Turbine Design. New turbines can be designed with efficient burners, more efficient heat transfer, to increase overall thermal efficiency. The function and near steady state operation of the turbines allows them to be designed to achieve "near best" thermal efficiency.

Good Combustion Practices. 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. Air to fuel ratios are tuned periodically to optimize these parameters and maximize the efficiency of the combustion process.

Periodic Maintenance Tune-ups. Periodic tune-ups of the turbines include:

- Preventive maintenance check of fuel gas flow meters annually,
- Periodically tune the air flows, and
- Cleaning of burner tips 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.

Use of Low Carbon (Natural Gas) Fuel. Natural gas is the lowest carbon fuel available for use in the proposed turbines. 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. Offgas and other fuels that will be used for the heaters and boilers are not recommended by the turbine vendors, and turbine performance and criteria pollutant emission limits cannot be guaranteed for fuels other than natural gas.

6.5.5 Step 5 – Selection of BACT

Good combustion practices, efficient boiler design, and tune-ups performed as needed are currently utilized on the existing turbines 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 turbines and are thus part of the selected BACT. These technologies and additional BACT practices proposed for the turbines are listed below:

- Waste Heat Recovery. Recovering waste heat from the turbine exhaust to the maximum extent possible in the WHB to produce steam for use at the plant is a keep plant energy feature as described in Section 6.1
- Use of low carbon fuel (natural gas). Natural gas will be the only fuel fired in the proposed turbines.
- Determine CO_2e emissions from the turbines based on metered fuel consumption and standard emission factors and/or fuel composition and mass balance.
- Good turbine design to maximize heat transfer efficiency and to reduce heat loss.
- Calibrate and perform preventive maintenance on the fuel flow meter once per year.

6.6 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.

6.6.1 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.

6.6.2 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 considered 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. Thus, although a thermal oxidizer may be a more effective control alternative than a flare for VOC emissions, it does nothing to reduce GHG emissions. For this reason, even if a thermal oxidizer 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.

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

6.6.3 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.

6.6.4 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.

6.6.5 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.

6.7 Fugitives (EPNs FUG-PDH & FUG-NGAS)

Hydrocarbon emissions from leaking piping components, (fugitives), in the process (EPN FUG-PDH) and in the natural gas pipeline (EPN FUG-NGAS) associated with the proposed project include methane, a GHG. The additional methane emissions from fugitives have been conservatively estimated to be 5 tpy as CO_2e from EPN FUG-PDH and 274 tpy as CO_2e from EPN FUG-NGAS as CO_2e. This is a negligible contribution to the total GHG emissions; however, for completeness, they are addressed in this BACT analysis.

6.7.1 Step 1 – Identification of Potential Control Technologies

The only identified control technology for a process fugitive emission 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.

6.7.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.7.3 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.

6.7.4 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.

6.7.5 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/LAER purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

6.8 Diesel Engines

The diesel engines will be used for emergency purposes only, and the only non-emergency operation will be for testing one hour per week each, or 52 weeks/yr.

6.8.1 Step 1 – Identification of Potential Control Technologies

The RBLC database did not include any control technologies for GHG emissions from emergency use engines. The technologies that were considered for the engines included:

- Low carbon fuel,
- Good combustion practice and maintenance, and
- Limited operation.

6.8.2 Step 2 – Elimination of Technically Infeasible Alternatives

Use of lower carbon fuel such as natural gas is not considered feasible for an emergency engine. Natural gas supplies may be unavailable in emergency situations, and maintaining the required fuel in an on-board tank associated with each engine is the only practical fuel option. Good combustion practice and maintenance and limited operation are both applicable and feasible.

6.8.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Limited operation and good combustion practices and maintenance are all effective in minimizing emissions, but do not lend themselves to ranking by effectiveness.

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

Limited operation is directly applicable to the proposed engines since they are for emergency use only, resulting in no emissions at most times. Operation for testing purposes is necessary to ensure operability when needed. Properly designed and maintained engines constitutes good operating practice for all maximizing efficiency of all fuel combustion equipment, including emergency engines.

6.8.5 Step 5 – Selection of BACT

Enterprises proposes to use properly designed and maintained engines to minimize emissions. Emergency use only inherently results in low annual emissions and normal operation will be limited to 52 hours per year for scheduled testing only. This minimal use results in an insignificant contribution to the total project GHG emissions making consideration of additional controls unwarranted. These practices are proposed as BACT for GHG emissions from the engines.

Table 6-1
Approximate Cost for Construction and Operation of a Post-Combustion CCS System for PDH Plant

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost
CO_2 Capture and Compression Facilities	$103	1,153,427	$118,803,012
CO_2 Transport Facilities[3]	Not Included	Not Included	Not Included
CO_2 Storage Facilities	$0.51	1,153,427	$588,248
Total CCS System Cost	$104	1,153,427	$119,391,260

Proposed Plant Cost	Total Capital Cost	Capital Recovery Factor[4]	Annualized Capital Cost
Cost of PDH Unit without CCS	$1,300,000,000	0.0944	$122,710,803

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 the proposed combustion units.

3. Pipeline costs are not included at this time. It is conservatively assumed that a suitable sequestration site is available in close proximaity to the proposed PDH Unit.

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

Interest Rate	7%
Equipent Life (yrs)	20

Appendix A

Emissions Calculations

Table A-1 GHG Emission Calculations

Enterprise Operating Products LLC

Mont Belvieu Complex - PDH Unit

GHG Emissions - Individual Combustion Unit Limts

EPN	FIN	Description	Fuel[1]	Firing Rate (mmBtu/yr)	Firing Rate (scf/yr)	Carbon Content (CC)	MW (lb/lbmol)	Emission Rates (tpy)[2] CO_2	CH_4	N_2O	CO_2e
HR15.101	HR15.101	Reactor Charge Heater	DeEth Offgas	3,758,478	2,503,713,725	0.765	26.66	246,846	12.43	2.49	247,877
			Ethane	508,582	287,383,412	0.798	30.07	33,322	0.56	0.06	33,351
			Natural Gas		494,432,362	0.723	17.46	30,139	0.56	0.06	30,168
		Reactor Charge Heater Total/Max[3]		**4,267,060**				**280,168**	**12.99**	**2.54**	**281,229**
DW37.101	All of Below:	Waste Heat Boiler:									
	HR15.103	Waste Heat Boiler Burner	Ethane	297,241	167,961,130	0.798	30.07	19,475	0.33	0.03	19,492
			DeEth Offgas	297,241	198,007,252	0.765	26.66	19,522	0.98	0.20	19,603
			Natural Gas	297,241	288,970,814	0.723	17.46	17,615	0.33	0.03	17,632
			PSA Tail Gas	297,241	599,900,478	0.443	11.14	14,315	0.33	0.03	14,332
			LTRU Offgas[4]	-	-	0.270	4.03	-	-	-	-
		WHB Burner Total/Max[5]		**297,241**				**19,522**	**0.98**	**0.20**	**19,603**
	HR15.102	Regeneration Air Heater	Ethane	4,789,100	2,706,164,815	0.798	30.07	313,779	5.28	0.53	314,053
			DeEth Offgas	3,758,478	2,503,713,725	0.765	26.66	246,846	12.43	2.49	247,877
			PSA Tail Gas	1,870,421	3,774,941,116	0.443	11.14	90,079	6.19	1.24	90,593
			Natural Gas	4,789,100	4,655,854,889	0.723	17.46	283,807	15.84	3.17	285,121
			LTRU Offgas[4]	-	-	0.270	4.03	-	-	-	-
		Regeneration Air Heater Total/Max[6]		**10,417,999**				**650,704**	**23.89**	**4.25**	**652,523**
	GT26.101A	Regen Air Comp. Gas Turbine A	Natural Gas	**2,107,571**	2,048,933,053	0.723	17.46	**124,897**	**2.32**	**0.23**	**125,018**
	GT26.101B	Regen Air Comp. Gas Turbine B	Natural Gas	**2,107,571**	2,048,933,053	0.723	17.46	**124,897**	**2.32**	**0.23**	**125,018**
BO10.103A	BO10.103A	Auxiliary Boiler A	Ethane	248,500	140,419,280	0.798	30.07	16,282	0.27	0.03	16,296
BO10.103B	BO10.103B	Auxiliary Boiler B	Natural Gas	248,500	241,586,096	0.723	17.46	14,726	0.82	0.16	14,795
			PSA Tail Gas	248,500	501,530,283	0.443	11.14	11,968	0.82	0.16	12,036
			DeEth Offgas	248,500	165,538,513	0.765	26.66	16,321	0.82	0.16	16,389
		Auxiliary Boiler Total/Max[7]		**248,500**				**16,321**	**0.82**	**0.16**	**16,389**

1 Listed fuels are the fuels that may be burned in each facility. All available DeEth Offgas and PSA Tail Gas will be used, and balance of required fuel will be natural gas and/or ethane. The fuel firing rates used for each facility are based on burning all available DeEth Offgas and PSA Tail Gas in the preferred facility, up to the required heat demand on that facility. Any remaining off/tail gas will be used in other facilities as shown. As such, the individual fuel usage rates used in the calculations are not maximum annual rates for each facility.

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.

3 All available DeEth Offgas will be burned in Reactor Charge Heater with balance of fuel being either natural gas or ethane. Total maximum emission rate is emissions from DeEth Offgas plus maximum from ethane or natural gas.

4 LTRU Offgas will only be burned if the PSA Unit is down, which is an upset condition and thus not shown in the calculations.

5 PSA Tail Gas is primary fuel for WHB Burner. Natural gas and ethane are alternate fuels. Maximum emission rate shown is based on burning 100% ethane.

6 Regeneration Air Heater will burn any DeEth Offgas and PSA Tail Gas not consumed in the Charge Heater and WHB Burner. Total/Max emissions are based on burning PSA Tail Gas not used in WHB Burner with balance of fuel from Ethane/DeEth Offgas. (Note that CO2 emission factor in lb/mmbtu for Ethane and DeEth Offgas are the same (see table below)).

7 Auxiliary Boilers will be in hot standby under normal conditions and will be used interchangeably; thus, the firing rates shown are totals for the two together. They are capable of burning each of the fuels listed, and maximum emissions are based on burning all DeEth Offgas, which results in the highest CO2 emisions.

Table A-1 GHG Emission Calculations

Enterprise Operating Products LLC

Mont Belvieu Complex - PDH Unit

GHG Emissions - Individual Combustion Unit Limts

Carbon Factor Calculations:

			Composition (mole %)						
Component	**Molecular Weight (lb/lb-mol)**	**Number of Carbons per mole**	**Natural Gas**	**DeEth Offgas (SOR)**	**PSA Tail Gas (SOR)**	**LTRU Offgas**	**Import Ethane**	**MSS Flaring**	**Reactor VOC**
Nitrogen	28.013	0	0.683	0.490	6.760	1.490	0.000	0.000	0.000
Carbon Dioxide	44.010	1	1.797	2.200	0.520	0.120	0.000	0.000	0.000
Carbon Monoxide	28.010	1	0.035	1.630	12.470	2.750	0.000	0.000	0.000
Helium	4.003	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Argon	39.95	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hydrogen	2.02	0	0.000	8.860	60.070	91.190	0.000	0.000	0.000
Methane	16.04	1	93.361	7.680	13.960	3.080	0.000	0.000	0.000
Ethane	30.07	2	3.043	71.330	3.470	0.770	100.000	0.000	1.530
Propane	44.10	3	0.557	0.060	0.760	0.170	0.000	50.000	8.113
Iso-Butane	58.12	4	0.191	0.000	0.000	0.000	0.000	0.000	0.000
n-Butane	58.12	4	0.143	0.000	0.000	0.000	0.000	0.000	9.672
Iso-Pentane	72.15	5	0.039	0.000	0.000	0.000	0.000	0.000	0.000
n-Pentane	72.15	5	0.027	0.000	0.000	0.000	0.000	0.000	7.792
n-Hexane	86.18	6	0.088	0.000	0.000	0.000	0.000	0.000	14.234
n-Heptane	100.20	7	0.000	0.000	0.000	0.000	0.000	0.000	12.241
C10+	140.00	10	0.000	0.000	0.000	0.000	0.000	0.000	43.807
Ethylene	28.05	2	0.000	7.170	0.970	0.210	0.000	0.000	0.182
Propylene	42.08	3	0.000	0.310	1.010	0.220	0.000	50.000	2.429
neo-Pentane	72.15	5	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Acetylene	26.04	2	0.000	0.220	0.010	0.000	0.000	0.000	0.000
Hydrogen Sulfide	34.00	0	0.000	0.050	0.000	0.000	0.000	0.000	0.000
Oxygen	32.00	0	0.037	0.000	0.000	0.000	0.000	0.000	0.000
Water	18.02	0	0.000	0.000	0.000	0.000	0.000	0.000	0.000
		MW (lb/lbmole):	**17.46**	**26.66**	**11.14**	**4.03**	**30.07**	**43.09**	**102.22**
		Carbon Content (kg C/kg Fuel):	**0.723**	**0.765**	**0.443**	**0.270**	**0.798**	**0.835**	**0.847**
		Heating Value (btu/scf, HHV):	**1028.6**	**1501.2**	**495.5**	**362.0**	**1769.7**	**NA**	**NA**
		CO2 emission factor (lb/mmbtu,HHV):	118.55	131.39	96.35	29.10	131.04		

Emission Factors:

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

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

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

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
Process Gas	0.003	0.0006
kg to lb conversion factor:		2.20462

CO2e Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

Table A-2 GHG Emission Calculations

Enterprise Operating Products LLC

Mont Belvieu Complex - PDH Unit

GHG Emissions - Combustion Unit Caps

EPN	FIN	Description	Firing Rate (mmBtu/yr)
HR15.101	HR15.101	Reactor Charge Heater	4,267,060
DW37.101	All of Below:	Waste Heat Boiler:	
	HR15.103	Waste Heat Boiler Burner	297,241
	HR15.102	Regeneration Air Heater	10,417,999
	GT26.101A	Regen Air Comp. Gas Turbine A	2,107,571
	GT26.101B	Regen Air Comp. Gas Turbine B	2,107,571
BO10.103A	BO10.103A	Auxiliary Boiler A	248,500
BO10.103B	BO10.103B	Auxiliary Boiler B	
Total from Above Combustion Units			**19,445,942**

Available Fuels:

Fuel[1]	Firing Rate (mmBtu/yr)
DeEth Offgas	3,758,478
PSA Tail Gas	2,167,662
Ethane	9,304,660
Natural Gas	4,215,142
Fuel Total	**19,445,942**

1. DeEth Offgas and PSA Tail Gas firing rates are all of these fuels that are projected to be produced annual in the process. All of these fuel gases will be burned in the PDH Unit combustion devices and the balance of the fuel requirements will be made up with either ethane or natural gas. Natural gas is the only fuel that will be fired in the Gas Turbines, and the natural gas firing rate shown is the fuel required for the two Gas Turbines. For the maximum annual GHG emissions calculations all remaining fuel requirements are assumed to be provided by ethane as ethane results in higher GHG emissions per btu than natural gas.

GHG Emission Calculation

Fuel	Firing Rate (mmBtu/yr)	Firing Rate (scf/yr)	Carbon Content (CC)	MW (lb/lbmol)	Emission Rates (tpy)[2]			
					CO_2	CH_4	N_2O	CO_2e
DeEth Offgas	3,758,478	2,503,713,725	0.765	26.66	246,846	12.43	2.49	247,877
PSA Tail Gas	2,167,662	4,374,841,594	0.443	11.14	104,394	7.17	1.43	104,989
Ethane	9,304,660	5,257,761,370	0.798	30.07	609,635	30.77	6.15	612,189
Natural Gas	4,215,142	4,097,866,106	0.723	17.46	249,794	13.94	2.79	250,950
Fuel Total	**19,445,942**	NA	NA	NA	**1,210,669**	**64.31**	**12.86**	**1,216,006**
VOC from Reactors	NA	13,333,260	0.847	102.22	5,580	-	-	5,580
Coke Burn[3]	NA	NA	NA	NA	60,000	-	-	60,000
Cap Total	NA	NA	NA	NA	**1,276,248**	**64.31**	**12.86**	**1,281,586**

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.

3. CO2 from coke burn based on Lummus EOR estimate of 58,000 tpy, rounded to 60,000 tpy.

Table A-2 GHG Emission Calculations

Enterprise Operating Products LLC

Mont Belvieu Complex - PDH Unit

GHG Emissions - Combustion Unit Caps

Carbon Factor Calculations:

Component	Molecular Weight (lb/lb-mol)	Number of Carbons per mole	Composition (mole %)					
			Natural Gas	DeEth Offgas (SOR)	PSA Tail Gas (SOR)	Import Ethane	Reactor VOC	LTRU Offgas[4]
Nitrogen	28.013	0	0.683	0.490	6.760	0.000	0.000	1.490
Carbon Dioxide	44.010	1	1.797	2.200	0.520	0.000	0.000	0.120
Carbon Monoxide	28.010	1	0.035	1.630	12.470	0.000	0.000	2.750
Helium	4.003	0	0.000	0.000	0.000	0.000	0.000	0.000
Argon	39.95	0	0.000	0.000	0.000	0.000	0.000	0.000
Hydrogen	2.02	0	0.000	8.860	60.070	0.000	0.000	91.190
Methane	16.04	1	93.361	7.680	13.960	0.000	0.000	3.080
Ethane	30.07	2	3.043	71.330	3.470	100.000	1.530	0.770
Propane	44.10	3	0.557	0.060	0.760	0.000	8.113	0.170
Iso-Butane	58.12	4	0.191	0.000	0.000	0.000	0.000	0.000
n-Butane	58.12	4	0.143	0.000	0.000	0.000	9.672	0.000
Iso-Pentane	72.15	5	0.039	0.000	0.000	0.000	0.000	0.000
n-Pentane	72.15	5	0.027	0.000	0.000	0.000	7.792	0.000
n-Hexane	86.18	6	0.088	0.000	0.000	0.000	14.234	0.000
n-Heptane	100.20	7	0.000	0.000	0.000	0.000	12.241	0.000
C10+	140.00	10	0.000	0.000	0.000	0.000	43.807	0.000
Ethylene	28.05	2	0.000	7.170	0.970	0.000	0.182	0.210
Propylene	42.08	3	0.000	0.310	1.010	0.000	2.429	0.220
neo-Pentane	72.15	5	0.000	0.000	0.000	0.000	0.000	0.000
Acetylene	26.04	2	0.000	0.220	0.010	0.000	0.000	0.000
Hydrogen Sulfide	34.00	0	0.000	0.050	0.000	0.000	0.000	0.000
Oxygen	32.00	0	0.037	0.000	0.000	0.000	0.000	0.000
Water	18.02	0	0.000	0.000	0.000	0.000	0.000	0.000
		MW (lb/lbmole):	**17.46**	**26.66**	**11.14**	**30.07**	**102.22**	**4.03**
		Carbon Content (kg C/kg Fuel):	**0.723**	**0.765**	**0.443**	**0.798**	**0.847**	**0.270**
		Heating Value (btu/scf, HHV):	**1028.6**	**1501.2**	**495.5**	**1769.7**	**NA**	**362.0**
		CO2 emission factor (lb/mmbtu,HHV):	**118.55**	**131.39**	**96.35**	**131.04**	**NA**	**29.10**

4 LTRU Offgas will only be burned if the PSA Unit is down, which is an upset condition and thus not shown in the calculations.

Emission Factors:

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

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

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
Process Gas	0.003	0.0006

kg to lb conversion factor: 2.20462

CO2e Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

Table A-3 GHG Emission Calculations

Enterprise Operating Products LLC
Mont Belvieu Complex - PDH Unit
Process Flare

EPN	FIN	Description	Fuel	Firing Rate (mmBtu/yr)	Firing Rate (scf/yr)	Carbon Content (CC)	MW (lb/lbmol)	Emission Rates (tpy)[1] CO_2	CH_4	N_2O	CO_2e
SK25.801	SK25.801	Process Flare, Routine									
		Pilots	Natural Gas	9,011	8,760,000	0.723	17.46	534	0.0099	0.0010	534
		Purge	Natural Gas	16,399	15,943,200	0.723	17.46	972	0.0181	0.0018	973
		Routine Steams	Vent Gas	3,354	7,545,545	0.835	43.09	1,312	0.0111	0.0022	1,313
		Routine Total						**2,818**	**0.04**	**0.005**	**2,821**
		Process Flare, MSS									
		Misc. MSS	Vent Gas	2,061	8,613,636	0.835	43.09	1,498	0.0068	0.0014	1,499
		Startup MSS	Vent Gas	46,006	45,913,143	0.735	17.96	2,928	0.1521	0.0304	2,941
		Shutdown MSS	Vent Gas	6,944	8,613,636	0.832	43.29	1,498	0.0230	0.0046	1,500
		MSS Total						**4,426**	**0.16**	**0.03**	**4,439**

1 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.

Carbon Factor Calculations:

Component	Molecular Weight (lb/lb-mol)	Number of Carbons per mole	Composition (mole %) Natural Gas	Startup Flaring	MSS Flaring	Shutdown Flaring
Nitrogen	28.013	0	0.683	0.000	0.000	0.000
Carbon Dioxide	44.010	1	1.797	2.000	0.000	0.000
Carbon Monoxide	28.010	1	0.035	0.000	0.000	0.000
Helium	4.003	0	0.000	0.000	0.000	0.000
Argon	39.95	0	0.000	0.000	0.000	0.000
Hydrogen	2.02	0	0.000	0.000	0.000	0.000
Methane	16.04	1	93.361	93.000	0.000	0.000
Ethane	30.07	2	3.043	0.000	0.000	0.000
Propane	44.10	3	0.557	3.000	50.000	60.000
Iso-Butane	58.12	4	0.191	0.000	0.000	0.000
n-Butane	58.12	4	0.143	0.000	0.000	0.000
Iso-Pentane	72.15	5	0.039	0.000	0.000	0.000
n-Pentane	72.15	5	0.027	0.000	0.000	0.000
n-Hexane	86.18	6	0.088	0.000	0.000	0.000
n-Heptane	100.20	7	0.000	0.000	0.000	0.000
C10+	140.00	10	0.000	0.000	0.000	0.000
Ethylene	28.05	2	0.000	0.000	0.000	0.000
Propylene	42.08	3	0.000	2.000	50.000	40.000
neo-Pentane	72.15	5	0.000	0.000	0.000	0.000
Acetylene	26.04	2	0.000	0.000	0.000	0.000
Hydrogen Sulfide	34.00	0	0.000	0.000	0.000	0.000
Oxygen	32.00	0	0.037	0.000	0.000	0.000
Water	18.02	0	0.000	0.000	0.000	0.000
		MW (lb/lbmole):	**17.46**	**17.96**	**43.09**	**43.29**
		Carbon Content (kg C/kg Fuel):	**0.723**	**0.735**	**0.835**	**0.832**
		Heating Value (btu/scf, HHV):	**1028.6**	**1028.6**	**311.0**	**927.6**
		CO2 emission factor (lb/mmbtu,HHV):	118.55			

Emission Factors:

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

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

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

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
Process Gas	0.003	0.0006
kg to lb conversion factor:		2.20462

CO2e Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

Table A-4 Pipeline Fugitive GHG Emission

Enterprise Operating Products LLC

Mont Belvieu Complex - PDH Unit

			EPN	LDAR		EPN	LDAR	
			FUG-NGAS	AVO		FUG-PDH	28LAER	
Component Type	**Stream Type**	**Emission Factor SOCMI without Ethylene**	**Number of Components**	**Control Eff.**	**Annual Emissions (tpy)**	**Number of Components**	**Control Eff.**	**Annual Emissions (tpy)**
Valves	Gas/Vapor	0.0089	140	30%	3.8202	1,119	97%	1.3086
	Light Liquid	0.0035	0	0%	0.0000	1495	97%	0.6876
	Heavy Liquid	0.0007	0	0%	0.0000	0	97%	0.0000
Pumps	Light Liquid	0.0386	0	0%	0.0000	51	93%	0.6036
	Heavy Liquid	0.0161	0	0%	0.0000	0	93%	0.0000
Flanges	Gas/Vapor	0.0029	350	30%	3.1120	3,851	97%	1.4675
	Light Liquid	0.0005	0	0%	0.0000	5263	97%	0.3458
	Heavy Liquid	0.00007	0	0%	0.0000	0	97%	0.0000
Compressors	Gas/Vapor	0.5027	0	0%	0.0000	4	95%	0.4404
Relief Valves	Gas/Vapor	0.2293	10	30%	7.0303	45	100%	0.0000
Open Ends		0.004	0	0%	0.0000	0	97%	0.0000
Sample Con.		0.033	0	0%	0.0000	32	97%	0.1388
Other	Gas/Vapor	0	0	0%	0.0000	0	97%	0.0000
	Lt/Hvy Liquid	0	0	0%	0.0000	0	97%	0.0000
Process Drains		0.07	0	0%	0.0000	0	97%	0.0000
TOTAL			500	Total Loss	**13.96**	11,860	Total Loss	**4.99**
Operating Hours: 8,760				% CH4	93%		% CH4	5%
				Total CH4	**13.04**		Total CH4	**0.25**
				GWP	21		GWP	21
				CO2e	**273.75**		CO2e	**5.24**

Table A-5 GHG Emission Calculations

Enterprise Operating Products LLC
Mont Belvieu Complex - PDH Unit
Diesel Engines

EPN	FIN	Description	Fuel	Firing Rate (mmbtu/hr)	Usage (hrs/yr)	Firing Rate (mmbtu/yr)	Emission Rates (tpy)[1]			
							CO_2	CH_4	N_2O	CO_2e
PM18.803	PM18.803	Fire Water Pump Engine	No. 2 Diesel	3.79	52	197	16.1	0.0007	0.0001	16.1
PM18.850C	PM18.850C	Raw Water Pump Engine	No. 2 Diesel	1.97	52	103	8.4	0.0003	0.0001	8.4

Emission Factors:

Emission factors from Tables C-1 & C-2 of Appendix A to 40 CFR Part 98 Chapter C

Fuel	kg CO2/mmBtu	kg CH4 /mmBtu	kg N2O/mmBtu
No. 2 Distillate	73.96	0.003	0.0006

kg to lb conversion factor: 2.20462

CO2e Equivalents:

CO2	1.0
CH4	21.0
N2O	310.0

Appendix B

RBLC Database Search Results

Appendix B

RBLC Database Search Results for GHG Emissions from Boilers

RBLCID	FACILITY_NAME	COMPANY_NAME	STATE	PERMIT DATE	PROCESS_NAME	PRIMARY FUEL	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1
AL-0231	NUCOR DECATUR LLC	NUCOR CORPORATION	AL	06/12/2007	VACUUM DEGASSER BOILER	NATURAL GAS	95 MMBTU/H	Carbon Dioxide		0.061 LB/MMBTU
*FL-0330	PORT DOLPHIN ENERGY LLC	PORT DOLPHIN ENERGY LLC	FL	12/01/2011	Boilers (4)	natural gas	278 MMBTU/H	Carbon Dioxide	tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Primary Reformer	natural gas	1.13 million cubic feet/hr	Carbon Dioxide	good combustion practices	117 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Primary Reformer	natural gas	1.13 million cubic feet/hr	Methane	good combustion practices	0.0023 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Primary Reformer	natural gas	1.13 million cubic feet/hr	Methane	good combustion practices	0.0023 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Primary Reformer	natural gas	1.13 million cubic feet/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	596905 TONS/YR
	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	natural gas	472.4 MMBTU/hr	Carbon Dioxide	good combustion practices	117 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	natural gas	472.4 MMBTU/hr	Methane	good combustion practices	0.0023 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	natural gas	472.4 MMBTU/hr	Nitrous Oxide (N2O)	good combustion practices	0.0006 LB/MMBTU
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Auxiliary Boiler	natural gas	472.4 MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	51748 TONS/YR
IN-0135	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	HOOSIER ENERGY REC INC. - MEROM GENERATING STATION	IN	11/10/2011	COAL BED METHANE CBM DEHYDRATOR UNITS (CBM-FIRED REBOILER AND FLASH TANK)	COAL BED METHANE	0.5 MMBTU/H	Carbon Dioxide	PROPER MAINTENANCE	59.36 LB/H
LA-0248	DIRECT REDUCTION IRON PLANT	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	LA	01/27/2011	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	Iron Ore and Natural Gas	12168 Billion Btu/yr	Carbon Dioxide	good combustion practices, the Acid gas separation system, and Energy integration.	11.79 MMBTU/TON OF DRI
LA-0248	DIRECT REDUCTION IRON PLANT	CONSOLIDATED ENVIRONMENTAL MANAGEMENT INC - NUCOR	LA	01/27/2011	DRI-208 - DRI Unit #2 Reformer Main Flue Stack	Iron ore and Natural Gas	12168 Billion Btu/yr	Carbon Dioxide	good combustion practices, the Acid gas separation system, and Energy integration.	11.79 MMBTU/TON OF DRI
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	08/16/2011	AUXILIARY BOILER (AUX	NATURAL GAS	338 MMBTU/H	Methane	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022 LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	08/16/2011	AUXILIARY BOILER (AUX-1)	NATURAL GAS	338 MMBTU/H	Nitrous Oxide (N2O)	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002 LB/MMBTU
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	LA	08/16/2011	AUXILIARY BOILER (AUX-1)	NATURAL GAS	338 MMBTU/H	Carbon Dioxide	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117 LB/MMBTU
*NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED	NE	03/01/2013	Boiler K	natural gas	300 mmbtu/h	Carbon Dioxide Equivalent (CO2e)	good combustion practices	0

RBLC Search of GHG BACT Database
12-Nov

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_1
*IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	IA	10/26/2012	Startup Heater	Natural gas	110.12 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	110.12 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	110.12 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	110.12 MMBTU/hr	Carbon Dioxide Equivalent (CO2e)	good combustion practices	638 TONS/YR
*MN-0085	ESSAR STEEL MINNESOTA LLC	ESSAR STEEL MINNESOTA LLC	MN	05/10/2012	INDURATING FURNACE	NATURAL GAS	542 MMBTU/H	Carbon Dioxide		710000 TON/YR

RBLC Database Search Results for GHG Emissions from Simple Cycle Turbines

RBLCID	FACILITY_NAME	COMPANY_NAME	STATE	PERMIT DATE	PROCESS_NAME	PRIMARY FUEL	THROUGHPUT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	LA	12/06/2011	Simple Cycle Refrigeration Compressor Turbines (16)	Natural Gas	286 MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107 TONS/YR
LA-0257	SABINE PASS LNG TERMINAL	SABINE PASS LNG, LP & SABINE PASS LIQUEFACTION, LL	LA	12/06/2011	Simple Cycle Generation Turbines (2)	Natural Gas	286 MMBTU/H	Carbon Dioxide Equivalent (CO2e)	Good combustion/operating practices and fueled by natural gas - use GE LM2500+G4 turbines	4872107 TONS/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_1
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