Application for PSD Permit
Greenhouse Gas Emissions
Condensate Splitter Project

Corpus Christi Terminal
Corpus Christi, Nueces County, Texas

Magellan Processing L.P.

November 2013
(Revised August 2014)

DiSorbo
Environmental Consulting Firm

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Section 1
Project Information

1.1 Introduction

Magellan Processing L.P. (Magellan) intends to construct and operate a condensate splitter located in Corpus Christi, Nueces County, Texas. The facility will be located in the Magellan Terminals Holdings, L.P. (MTH) Corpus Christi Terminal.

The condensate splitter will be constructed in two phases. Each phase will consist of an identical splitter train that will each process 50,000 bbl/day of hydrocarbon condensate material to obtain products suitable for commercial use. Construction of the second 50,000 bbl/day train is expected to commence within 18 months of completion of the first 50,000 bbl/day train. The process will utilize conventional distillation technology.

Table 1-1 presents a summary of the proposed facility project emissions of Greenhouse Gases (GHG). This document constitutes an application from Magellan for the required U.S. Environmental Protection Agency (EPA) PSD GHG air quality permit. This application includes both routine and planned maintenance, startup, and shutdown (MSS) emissions associated with the new condensate splitter. This submittal incorporates all revisions that have been made to the application during the EPA review since the original November 2013 submittal and constitutes Magellan's final application to be used as the basis of the issued GHG PSD permit.

1.2 Application Organization

This application is organized into the following sections:

Section 1 presents the application objectives and organization;

Section 2 presents administrative information and PSD applicability forms for GHG emissions;

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

Section 4 contains a process description and process flow diagram for the Condensate Splitter.

Section 5 presents the basis of the GHG emissions calculations for each emission point.

Section 6 presents the Best Available Control Technology (BACT) analysis for the proposed facilities.

Appendix A contains the emissions calculations for each GHG emission point.

Appendix B contains the results of the RACT/BACT/LAER Clearinghouse (RBLC) search that supports the BACT analysis.

Appendix C contains detailed process flow diagrams for the splitter the process.

Table 1-1
Project GHG Emission Summary
Magellan Condensate Splitter Project

Source	FIN	EPN	Project Phase	CO_2 tpy	CH_4 tpy	N_2O tpy	CO_2e tpy
Fractionator Heater H-1A (149 MMBtu/hr)[1]	H-1A	H-1A	1	76,342	1.44	0.14	76,420
Hot Oil Heater H-1B (55 MMBtu/hr)[1]	H-1B	H-1B	1	28,180	0.53	0.05	28,209
Fractionator Heater H-2A (149 MMBtu/hr)[1]	H-2A	H-2A	2	76,342	1.44	0.14	76,420
Hot Oil Heater H-2B (55 MMBtu/hr)[1]	H-2B	H-2B	2	28,180	0.53	0.05	28,209
Tank Heater H-3 (16 MMBtu/hr)[1]	H-3	H-3	1	8,198	0.15	0.02	8,206
Tank Heater H-4 (16 MMBtu/hr)[1]	H-4	H-4	1				
Marine Vapor Combustor	VCU1/VCU2	VCU1/VCU2	1	11,592	3.6E-01	6.4E-02	11,620
Fugitives[2]	FUG-1	FUG-1	1	0	6.42	0	160
Flare - Routine	FL-1	FL-1	1	125	2.4E-03	2.4E-04	125
Fire Water Pump	FWP1	FWP1	1	32	1.3E-03	2.6E-04	32
Backup Fire Water Pump	FWP2	FWP2	1	32	1.3E-03	2.6E-04	32
Emergency Generator 1	EMGEN1	EMGEN1	1	39	1.6E-03	3.1E-04	39
Emergency Generator 2	EMGEN2	EMGEN2	1	8	3.1E-04	6.2E-05	8
Flare - MSS	FL-1	FL-1	1	451	1.8E-02	3.6E-03	452
MSS Vapor Combustor	MSSVCU	MSSVCU	1	3,721	7.7E-02	9.2E-03	3,725
			Project Total (tpy)	**233,240**	**11**	**0.5**	**233,660**

1. Annual average firing rate. Maximum hourly rates can be higher.
2. Fugitive emissions have been updated based on current design details.

Section 2
Administrative Information

This section contains the following forms:

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

The administration information on the following page contains facility details and contact information regarding this project. Also included is an original signature from the responsible official indicating that the information contained in this application is true and correct, based on the best available information. Please note that the project is still in the planning phases and therefore the information used to develop this application is subject to change.

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 increases from the project exceed 75,000 tpy of CO_2e, therefore, emissions netting is required for GHG emissions. Table 3F presents the netting analysis. After netting, the proposed facility is considered to be a major modification as defined in the Prevention of Significant Deterioration (PSD) regulations, and PSD review is required for the GHG emissions from the project. The project is also a major modification for VOC emissions; therefore, PSD review is triggered for VOC emissions. TCEQ has authority for PSD permitting of VOC; therefore, the TCEQ is responsible for the associated Additional Impacts Analysis as part of the PSD permit review for VOC, and it is not included in this GHG permit application.

Administrative Information

Company or Other Legal Name: Magellan Processing L.P.		
Company Official Contact Name (☐ Mr. ☐Mrs. ☒Ms. ☐Dr.): Melanie Little		
Title: Vice President of Operations		
Mailing Address: One Williams Center, MD 27		
City: Tulsa	State: OK	ZIP Code: 74172
Telephone No.: 918-574-7306	Fax No.:	E-mail Address: melanie.little@magellanlp.com
Technical Contact Name: Ms. Shahana Banoo		
Title: Air Specialist, Sr.		
Company Name: Magellan Processing, L.P.		
Mailing Address: One Williams Center, MD 27		
City: Tulsa	State: OK	ZIO Code: 74172
Telephone No.: 918-574-7767	Fax No.: 918-574-7760	E-mail Address: shahana.banoo@magellanlp.com
Facility Location Information:		
Street Address: 1802 Poth LN		
Latitude: 27° 48' 29.34"	Longitude: 97° 26' 12.25"	
If no street address, provide clear driving directions to the site in writing:		
City: Corpus Christi	County: Nueces	ZIP Code: 78407
TCEQ Account Identification Number (leave blank if new site or facility):		
TCEQ Customer Reference Number *(leave blank if unknown):* RN102536836		
TCEQ Regulated Entity Number *(leave blank if unknown)*: CN604541797		
Site Name: Corpus Christi Terminal		
Area Name/Type of Facility: Condensate Splitter	☒ Permanent ☐ Portable	
Principal Company Product or Business: Natural Gas Liquids Processing		
Principal Standard Industrial Classification Code: 1321 – Natural Gas Liquids		
Projected Start of Construction Date: 1/15/2015	Projected Start of Operation Date: 1/01/2016	
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: Ms. Melanie Little		
SIGNATURE: Melanie Little *Original Signature Required*		
DATE: 8/11/14		

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **Nov, 2013 (Revised August 11, 2014)**
Company: **Magellan Processing L.P.**	
RN: **TBD**	Facility Location: **1802 Poth Lane**
City: **Corpus Christi**	County: **Nueces**
Permit Unit I.D.: **see application**	Permit Name: **Corpus Christi Terminal**
Permit Activity: New Source _____ Modification __X__	**Condensate Splitter Facility**

Complete for all Pollutants with a Project Emission Increase.	POLLUTANTS							
	Ozone							
	VOC	NOx	CO	PM_{10}	$PM_{2.5}$	NOx	SO2	CO2e
Nonattainment?								No
PSD?								Yes
Existing site PTE (tpy)?								>100,000
Proposed project emission increases (tpy from 2F)?								233,660
Is the existing site a major source?								Yes
If not, is the project a major source by itself?								
If site is major, is project increase significant?								Yes
If netting required, estimated start of construction:	15-Jan-15							
Five years prior to start of construction	15-Jan-10							contemporaneous
Estimated start of operation	1-Jan-16							period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)								245,478
Major NSR Applicable?								Yes

Name: Melanie Little	Title: Vice President of Operations
Signature: Melanie Little	Date: 8/11/14

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

Table 2F - GHG
Project Emission Increase

Pollutant: GHG	Permit No.: TBD
Baseline Period: 2011-2012	

	Affected or Modified Facilities		Permit No.	Actual Emissions (tons/yr)	A Baseline Emissions (tons/yr)	B Proposed Emissions (tons/yr)	Projected Actual Emissions (tons/yr)	Difference (B-A) (tons/yr)	Correction (tons/yr)	Project Increase (tons/yr)
	FIN	EPN								
1	H-1A	H-1A	TBD	-	-	76,420	-	76,420	-	76,420
2	H-1B	H-1B	TBD	-	-	28,209	-	28,209	-	28,209
3	H-2A	H-2A	TBD	-	-	76,420	-	76,420	-	76,420
4	H-2B	H-2B	TBD	-	-	28,209	-	28,209	-	28,209
5	H-3	H-3	N/A*	-	-	8,206	-	8,206	-	8,206
6	H-4	H-4	TBD	-	-					
7	FL-1 (Routine)	FL-1 (Routine)	TBD		-	125	-	125	-	125
8	VCU1/VCU2	VCU1/VCU2	TBD	-	-	11,620	-	11,620	-	11,620
	FUG-1	FUG-1	TBD	-	-	160		160		160
9	FWP1	FWP1	TBD	-	-	32	-	32	-	32
10	FWP2	FWP2	TBD	-	-	32	-	32	-	32
11	EMGEN1	EMGEN1	TBD	-	-	39	-	39	-	39
12	EMGEN2	EMGEN2	TBD	-	-	8	-	8	-	8
13	FL-1 (MSS)	FL-1 (MSS)	TBD	-	-	452	-	452	-	452
14	MSSVCU	MSSVCU	TBD	-	-	3,725	-	3,725	-	3,725
15	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-
25	-	-	-	-	-	-	-	-	-	-
26	-	-	-	-	-	-	-	-	-	-
* Unregistered PBR authorization									***Page Subtotal:***	***233,660***

Table 3F
Project Contemporaneous Changes

Company : Magellan Processing, L.P.

Permit Application No.: | **Criteria Pollutant:** GHG

	Project Date	Facility at Which Emission Change Occurred		Permit No.	Project Name or Activity	Baseline Period	A Baseline Emissions (tons/yr)	B Proposed Emissions (tons/yr)	Difference (B-A)	Creditable Decrease or Increase
		FIN	EPN							
1	4/16/2012	VCU1/VCU2	VCU1/VCU2	56470	Consolidate Permit 5970 and new VCU.	N/A	753	12,557	11,803	11,803
2	(pending)	VCU-MSS	VCU-MSS	56470	MSS emissions	N/A	0.00	15	15	15
3	1/1/2016	H-1A	H-1A	TBD	Condensate Splitter Project	N/A	0.00	76,420	76,420	76,420
		H-1B	H-1B			N/A	0.00	28,209	28,209	28,209
		H-2A	H-2A			N/A	0.00	76,420	76,420	76,420
		H-2B	H-2B			N/A	0.00	28,209	28,209	28,209
		H-3	H-3			N/A	0.00	8,206	8,206	8,206
		H-4	H-4			N/A	0.00			
		FL-1 (Routine)	FL-1 (Routine)			N/A	0.00	125	125	125
		VCU1/VCU2	VCU1/VCU2			N/A	0.00	11,620	11,620	11,620
		FUG-1	FUG-1			N/A	0.00	160	160	160
		FWP1	FWP1			N/A	0.00	32	32	32
		FWP2	FWP2			N/A	0.00	32	32	32
		EMGEN1	EMGEN1			N/A	0.00	39	39	39
		EMGEN2	EMGEN2			N/A	0.00	8	8	8
		FL-1 (MSS)	FL-1 (MSS)			N/A	0.00	452	452	452
		MSSVCU	MSSVCU			N/A	0.00	3,725	3,725	3,725
									PAGE SUBTOTAL:	245,478
									Total:	**245,478**

Section 3
Location Information

An area map showing the location of the Condensate Splitter and the Corpus Christi Terminal is included as Figure 3-1. A plot plan of the Condensate Splitter is provided as Figure 3-2.

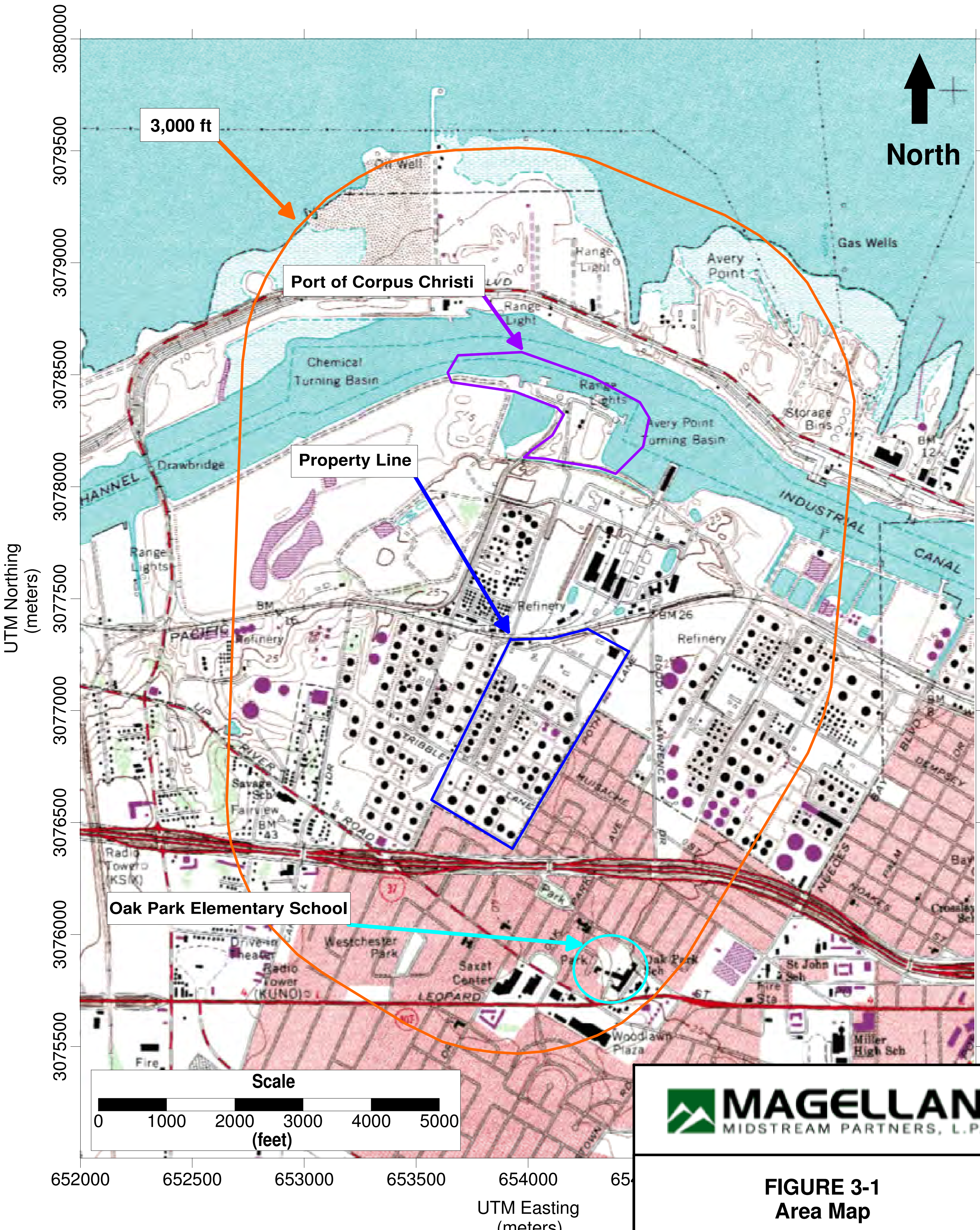


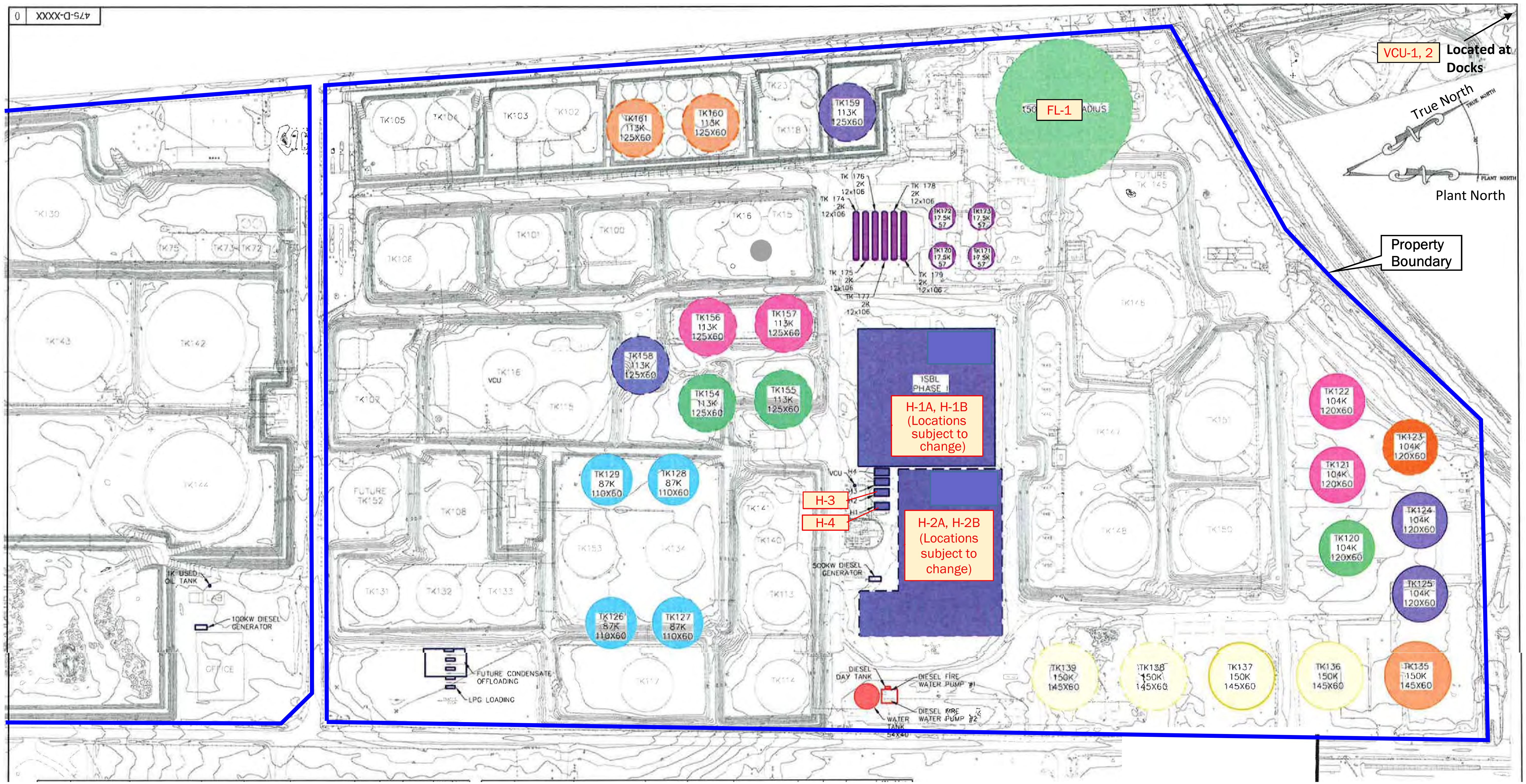
FIGURE 3-1
Area Map

MAGELLAN MIDSTREAM PARTNERS, L.P.

RPS

Cielo Center
1250 South Capital of Texas Highway
Building Three, Suite 200
Austin, Texas 78746, USA

Source: mytopo.com/
Zone: 14
Coordinate Datum: NAD 83



Equipment locations are based on current design and are subject to change based on as built design.

GRAPHIC SCALE

(IN FEET)
1 inch = 100 ft.

MAGELLAN MIDSTREAM PARTNERS, L.P.

Magellan Processing, L.P.
Condensate Splitter Project
Corpus Christi, Nueces County, Texas

DiSorbo Environmental Consulting Firm

Figure 3-2
Process Area Plot Plan

Section 4
Process Description

The Magellan condensate splitter facility to be installed at the Corpus Christi Terminal will process 100,000 bbls/day of a hydrocarbon condensate material (including both condensate and crude oil) to obtain products suitable for commercial use or as feedstock for further refining. The facility will consist of two trains processing 50,000 bbls/day each of condensate, with Phase 1 being the initial 50,000 bbls/day installation and Phase 2 an identical train to be installed in the future. The process described in the following paragraphs utilizes conventional distillation technology for the specified range of condensate feed. This process description reflects the project design as of submittal of this final revised document and is subject to change. If any additional design changes that affect the GHG emissions, Magellan will apply for a permit amendment to incorporate any required changes.

The hydrocarbon condensate is fed from storage tanks to the prefractionator column. In the prefractionator column the lightest fraction of the condensate is distilled from the overhead at a pressure that will permit complete condensation. Any incondensable material that may be produced will be used as fuel gas in the heaters (EPNs H-1A, H-1B, H-2A, and H-2B). Overhead liquid from the prefractionator column is cooled and sent to two additional fractionation columns to further refine the stream. The bottoms stream from the prefractionation column is pumped into a downstream fired heater and into the main fractionation column. Heat is supplied to the prefractionator by means of a hot oil heater (EPNs H-1B and H-2B).

The liquid overhead stream from the prefractionator column is pumped to a depropanizer column. The column overhead vapor is condensed with an air cooler. The propane product is recovered from an overhead accumulator where it is sent to pressurized storage tanks. Heat is supplied to the depropanizer column using the hot oil system.

The bottoms stream from the depropanizer column is pressured to a debutanizer column. The overhead vapor is condensed with an air cooler. The butane product is recovered from an overhead accumulator where it is sent to pressurized storage tanks. Heat is supplied to the debutanizer column using the hot oil system. The debutanizer bottoms product, light naphtha, is cooled and sent to storage.

The main fractionation column separates the bottoms from the prefractionation column into four products. These products include heavy naphtha, jet fuel, diesel, and residual liquid (resid). The net overhead product, heavy naphtha, is cooled and pumped to storage. The jet and diesel are recovered from the column as side streams and pumped to storage. The fractionator bottoms product, resid, is cooled, and then sent to storage. This product is the heaviest fraction of the condensate.

In addition to the main process equipment described above, the condensate splitter requires certain support systems. An existing tank heater (EPN H-3) and a new tank heater (EPN H-4) will be used as needed to provide heat to storage tanks and dock lines. The tank heaters, which use oil as a heat transfer medium, are only anticipated to be needed during the cooler months. A flare (EPN FL-1) is provided for use in emergency overpressure situations to dispose of excess process vapors. The flare also controls routine process streams and vapors from specific MSS activities. The routine streams to the flare include pilot gas, purge gas, and intermittent flow associated with the unit's vapor control. This flare utilizes a continuous pilot to ensure that unexpected release events result in safe disposal. Fuel gas to the plant is supplied by natural gas pipeline. A new fire water pump (EPN FWP1), a backup firewater pump (EPN FWP2), and two new emergency backup generators (EPNs EMGEN1 and EMGEN2) are also included with this project. Two new diesel fuel tanks will store fuel for the emergency combustion units.

Existing Port of Corpus Christi docks and Magellan marine vapor combustor controls (EPNs VCU1 and VCU2) will be utilized to transfer products offsite. Two new loading dock lines will be added, and piping modifications will be made to the existing docks. LPG (propane/butane) product will be transferred under pressure to tank trucks at a new loading rack. Condensate off-loading will also occur at the loading rack. All of the products may be transferred to local refineries and terminals via pipelines.

This application also includes maintenance, startup, and shutdown (MSS) activities. A vapor combustion unit (EPN MSSVCU) will be installed at the facility to control vapors generated during certain MSS activities including storage tank roof landings, process vessel and piping maintenance, and pressurized tank maintenance activities. Vacuum trucks, vacuum boxes, and frac tanks may be used to collect and store liquids generated during MSS activities. Product samples will be collected and tested onsite using a bench scale lab. Leftover sample liquid will be stored in a tank.

Magellan is also planning a potential wastewater treatment system for the splitter process that may consist of a desalter, a CPI gravity plate separator, an Induced Gas Floatation (IGF) stage, and a nut shell filter. In addition one oil-water separator may be added to the facility. The CPI separator and

IGF stage are potential sourced of VOC emissions and will be enclosed and vented to the MSS vapor combustor for control.

A simplified process flow diagram is included as Figure 4-1. Detailed process flow diagrams are included in Appendix C.

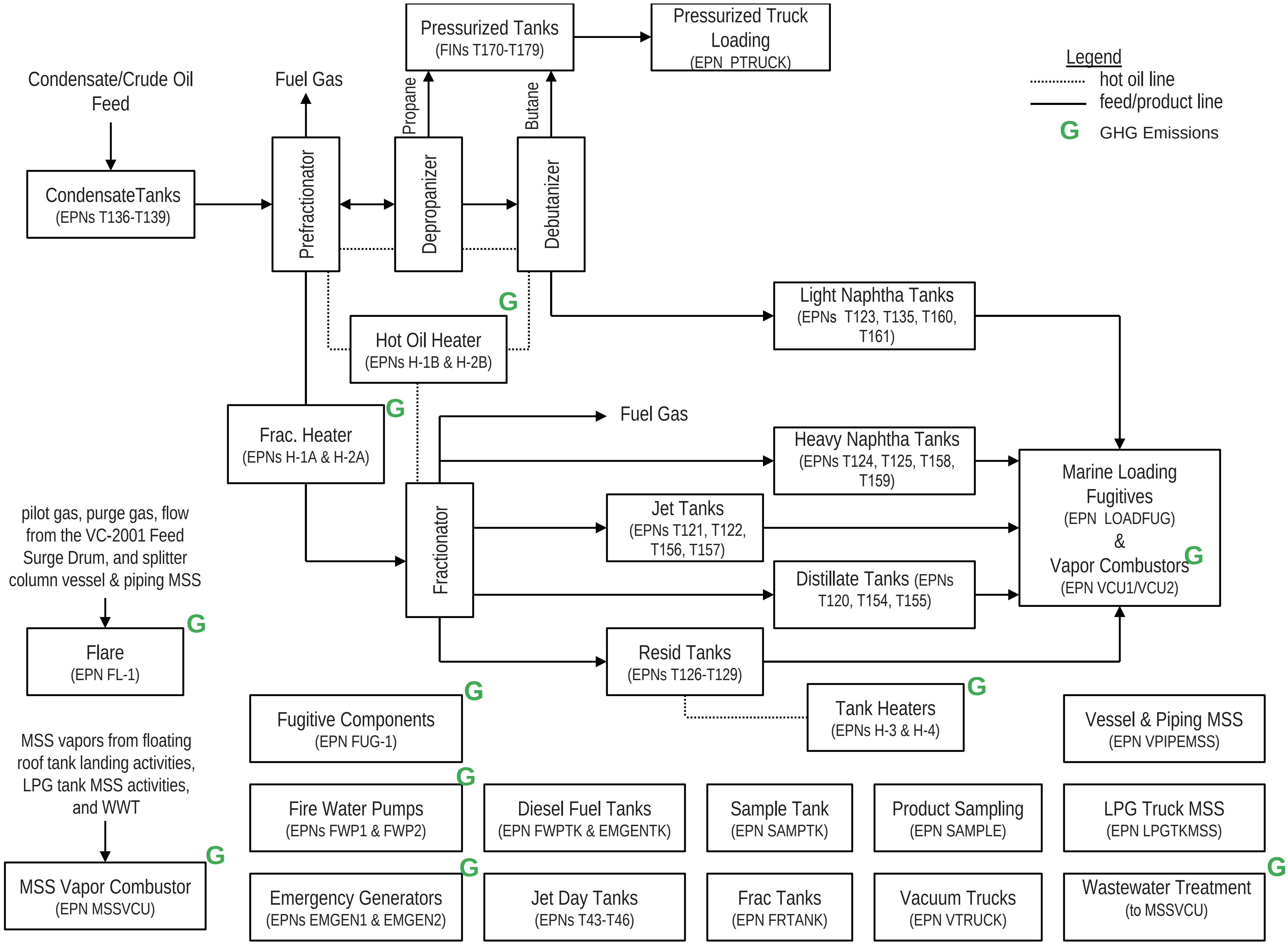


Figure 4-1 ◆ Magellan Processing L.P. ◆ Condensate Splitter Project ◆ Corpus Christi, Texas

Section 5
Emission Calculations

This section describes the emissions calculations for the proposed allowable GHG emission rates for each facility that will be part of the proposed Condensate Splitter. The proposed emissions limits are found in Table 1-1 of the introduction to this permit application. GHGs emitted from the proposed facilities include carbon monoxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). Magellan does not anticipate emissions of hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), or sulfur hexafluoride (SF_6) from the proposed facilities. The carbon dioxide equivalent (CO_2e) emission rates are based on the estimated mass emission rates for each applicable GHG multiplied by the global warming potential (GWP) for each specific GHG per 40 CFR Part 98, Subpart A, Table A-1. Detailed individual GHG mass emission calculations as well as the corresponding CO_2e emission rates are presented in Appendix A of this application. Both routine and MSS emissions are addressed in this application and the emission calculations for both types are discussed below.

5.1 Routine GHG Emissions

Appendix A provides a summary of the routine GHG emissions included in this application from the following facility types:

- Heaters,
- Flare (routine and MSS),
- Natural Gas Pipeline Fugitives,
- Marine and MSS Vapor Combustors,
- Firewater Pump and Emergency Generator Diesel Engines.

5.1.1 Heaters

The new Condensate Splitter process will include two new natural gas fired process heaters for each train: the Hot Oil Heaters (H-1B and H-2B) and the Fractionator Heaters (H-1A and H-2A). One existing (H-3) and one new (H-4) gas-fired Tank Heater will also support the process. Non-condensible gas produced by the splitter process will also contribute approximately 4% of the total annual heat input to the Hot Oil and Fractionator Heaters. The composition of this fuel gas, shown in Appendix A, Table A-1a, is very similar to natural gas. The CO_2 factor in lb/MMBtu, calculated in Table A-1a, shows that the emissions will be within 3% of that of natural gas; therefore, the contribution to the emissions was not differentiated from natural gas in the calculations. Heater GHG emission calculations are included in Appendix A as Table A-1. Emissions are based on the annual average firing rates and default natural gas emission factors for CO_2, CH_4, and N_2O from 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

Tank Heater usage will be intermittent, and the two tank heaters will be interchangeable; therefore, emission caps calculated from the total combined annual heat input are proposed for these two heaters.

5.1.2 Flare

The new Condensate Splitter will utilize a process flare which is designed for control of routine emissions and venting during planned MSS and upset situations. The routine streams to the flare include pilot gas, purge gas, and intermittent flow associated with the vapor control on the Feed Surge Drum. The flare will be designed to achieve a VOC destruction efficiency of at least 98%. Flare pilot GHG emission calculations are included in Appendix A as Table A-4. GHG emissions associated with anticipated MSS activities controlled via the process flare are discussed in Section 5.2.2.

Natural gas used as pilot gas contains hydrocarbons, primarily CH_4, that also produce GHG emissions when burned. Any unburned CH_4 from the flare will also be emitted to the atmosphere along with small quantities of N_2O emission resulting from the combustion process. Emissions of these pollutants were calculated based on the equations and emission factors taken from 40 CFR Part 98. These equations and factors were applied to the maximum projected natural gas flow rates to the process flare.

5.1.3 Natural Gas Pipeline Fugitives

The new Condensate Splitter will include new natural gas piping components. Calculations of the fugitive GHG emission from these components calculations are included in Appendix A as Table A-5. Fugitive emission rates of VOC, including CH_4, from piping components and ancillary equipment were estimated using the methods outlined in the TCEQ's Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

Component counts are an engineering estimate based on similar facilities. Each fugitive component was classified first by equipment type (i.e., valve, pump, relief valve, etc.) and then by material type (i.e., gas/vapor, light liquid, heavy liquid). An uncontrolled emission rate was obtained by multiplying the number of fugitive components of a particular equipment/material type by an appropriate emission factor. Synthetic Organic Chemical Manufacturing Industry (SOCMI) factors (without ethylene) were used to estimate emissions from the proposed components as the streams have an ethylene content of <11%.

To obtain controlled fugitive emission rates, the uncontrolled rates were multiplied by a control factor, which was determined by the type of leak detection and repair (LDAR) program employed. Magellan will implement an audio, visual, and olfactory (AVO) LDAR program for natural gas piping fugitive components associated with the proposed Condensate Splitter. The emissions were assumed to be 100% CH_4.

5.1.4 Marine Vapor Combustors

Product from the Condensate Splitter will be transported off-site by pipeline, tank truck, ship, and barge. Truck loading will be used for liquids with vapor pressures above atmospheric pressure. The truck loading operations will be vapor balanced and loaded into pressurized tank trucks with no venting to the atmosphere and thus no GHG emissions.

Marine loading will be used to transport other Condensate Splitter products from the facility. Marine loading emissions are controlled using two existing marine vapor combustion units (VCUs). The combustion products from the marine VCUs will result in GHG emissions (CO_2, CH_4, and N_2O). The GHG emission calculations from the marine loading operations are included in Appendix A, Table A-2. Emissions were calculated by first calculating the VOC emissions resulting from loading activities as described in TCEQ's Air Permit Technical Guidance for Chemical Sources: Loading Operations (October 2000) using the following equation from AP-42 "Compilation of Air Pollutant Emission Factors, Volume I, Stationary Point and Area Sources":

$$L = 12.46 * S * P * M/T$$

Where:
L = Loading Loss, lb/10^3 gal of liquid loaded
S = Saturation factor
P = True vapor pressure of liquid loaded, psia
M = Molecular weight of vapors, lb/lb mole
T = Temperature of bulk liquid loaded, °R

The VOC loading emission estimates were based on the physical property data of the material loaded and the actual loading method used. The VOC vapors from loading products with a vapor pressure greater than 0.5 psia will be collected by a vapor collection system and routed to one of the two marine VCUs that will have a minimum destruction efficiency of 99.5%. GHG emissions were then estimated using the total annual heat input of the collected vapors and GHG emission factors for

CO_2, CH_4, and N_2O from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Natural gas used to support combustion of the vapors will also result in GHG emissions. The GHG emissions were calculated from the estimated annual natural gas combustion rate and the default GHG emission factors for natural gas in 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

5.1.5 Emergency Combustion Devices

There will be two diesel fired firewater pump engines and two diesel fired emergency generator engines. Other than emergency use, the engines will be operated no more than 100 hours per year each for testing purposes. GHG emissions are calculated based on the annual fuel firing rate in MMBtu/yr and GHG emission factors in kg/MMBtu for diesel (No. 2 distillate) fuel from 40 CFR Part 98, Subpart C, Tables C-1 and C-2. Table A-6 of Appendix A presents the emissions calculations from these engines.

5.2 Maintenance, Startup, and Shutdown Emissions

Table A-7 in Appendix A provides a summary of the GHG MSS emissions associated with the Condensate Splitter operation. GHG MSS emissions are only expected to be generated during controlled storage tank roof landings, pressure vessel maintenance, and process vessel and piping maintenance. Depending on the vapor pressure of the material in storage or in the process, prior to maintenance the vapors from these tanks, vessels, and piping will be collected and routed to either the flare or the MSS vapor combustor for control. The GHG emissions are generated by these combustion devices. Vacuum truck operations and frac tanks are not expected to use combustion control and therefore will not generate GHG emissions.

5.2.1 MSS Vapor Combustor

A new MSS VCU will be installed to control vapors from various MSS activities, including internal floating roof tank landings, purging of pressure tanks, and the wastewater treatment system vents. If the material stored in the tanks has vapor pressure greater than 0.5 psia, the MSS VCU will be used to control the emissions when the tanks are degassed for maintenance purposes. Combustion of the degassing vapors in the MSS VCU produces GHGs. The GHG emissions are calculated by multiplying the total annual heat input of the vapors MMBtu/yr) by GHG emission factors in kg/MMBtu from Tables C-1 and C-2 in 40 CFR Part 98, Subpart C. Emission rates were then converted from kg/yr to tons/yr. Calculation of the tank vapor flow rates were based on TCEQ guidance and AP-42 equations. The calculations for each activity are described in the following subsections.

5.2.1.1 IFR Storage Tank MSS

Storage tank floating roof landing emissions were estimated following TCEQ guidance and using the methods in Subsection 7.1.3.2.2 Roof Landings of Section 7.1 Organic Liquid Storage Tanks of Compilation of Air Pollutant Emission Factors: Volume 1 Stationary Point and Area Sources (AP-42), Fifth Edition, US EPA, November 2006.

Landing losses occur from floating roof tanks whenever the tank is drained to a level where its roof lands on its legs or other supports (including roof suspension cables). When a floating roof lands on its supports or legs while the tank is being drained, the floating roof remains at the same height while the product level continues to lower. This creates a vapor space underneath the roof. Liquid remaining in the bottom of the tank provides a continuous source of vapors to replace those expelled by breathing (in the case of internal floating roof tanks) or wind action (in the case of external floating roof tanks). These emissions, referred to as standing idle losses (LSL), occur daily as long as the floating roof remains landed.

If Magellan plans to enter a tank, or if the material vapor pressure is greater than 0.5 psia and the roof remains landed for more than 24 hours, the tank is degassed. The vapors removed from the vapor space under the floating roof are routed to a control device. Control is maintained until the concentration reaches 2,000 parts per million by volume (ppmv) as methane after which the tank may vent to atmosphere. These emissions are referred to as degassing losses.

Additional emissions occur when tank with a landed roof is refilled. The incoming volume generates vapors into the vapor space below the landed roof that are expelled as the liquid fills the vapor space. These emissions are referred to as refilling losses (LFL).

For a given roof landing event, total landing loss emissions are therefore the sum of the filling losses, degassing and cleaning losses (if applicable), and the daily standing idle losses over the entire period that the roof remained landed. Landing losses are inherently episodic in nature and must be determined each time a tank's floating roof is landed.

The calculation methodology used to estimate the standing losses, degassing, and refilling emissions is discussed in further detail below. Specific details of the calculations and the equations used are include in Tables A-8a and A-8b of Appendix A.

Standing Idle Losses - Emission calculation equations for these losses are from Subsection 7.1.3.2.2.1 Standing Idle Losses in Section 7.1 Organic Liquid Storage Tanks of Compilation of Air

Pollutant Emission Factors: Volume 1 Stationary Point and Area Sources (AP-42, Fifth Edition, US EPA, November 2006). The quantity of emissions is dependent upon the number of days idle, tank type (IFR/EFR), type of product stored, and time of year.

Storage Tank Degassing - There are two components to the emissions during a tank degassing: degassing to a control device and venting the dilute residual VOC to the atmosphere. The first component results in GHG emissions. These emissions are based on the ideal gas law along with an estimated saturation factor, vapor flow rate, and number of tank volume turnovers. Calculations were performed for the tank using the landed roof volume calculated from the tank diameter and the landed roof height.

Refilling Losses - Refilling losses occur when a tank is refilled with product during the period when the space below the landed roof is displaced by the incoming liquid. Emission calculation equations for these losses are from Subsection 7.1.3.2.2.2 Filling Losses in Section 7.1 Organic Liquid Storage Tanks of *Compilation of Air Pollutant Emission Factors: Volume 1 Stationary Point and Area Sources* (AP-42, Fifth Edition, US EPA, November 2006). The quantity of emissions is dependent upon the tank type (IFR/EFR), type of product stored, time of year, and fill rate. The refilling emissions from IFR tanks with a liquid heel and tanks that are drained dry are based on Equation 2-26 from AP-42.

5.2.1.2 Pressure Tank Purging

Pressure spheres that store LPG, butane, and propane are periodically taken out of service for maintenance or inspection. Prior to opening, liquid is drained, and the vapor space is purged to the MSS VCU. The vapor mass rate to the MSS VCU is based on the ideal gas law applied to the tank volume at the storage pressure of each material and the properties (molecular weight) of the material. The emissions calculations are included in Table A-9 of Appendix A.

5.2.1.3 Assist Natural Gas

Natural gas used as pilot and assist gas contains in the MSS VCU contains hydrocarbons, primarily CH_4, that also produce GHG emissions when burned. Any unburned CH_4 from the MSS VCU will also be emitted to the atmosphere along with small quantities of N_2O emission resulting from the combustion process. Emissions of these pollutants were calculated based on the equations and emission factors taken from 40 CFR Part 98 and are presented in Table A-10 of Appendix A. These equations and factors were applied to the maximum projected natural gas flow rates to the MSS VCU.

5.2.2 MSS Flaring

GHG emissions are produced from the combustion of purged vapors from miscellaneous vessels and piping to the flare prior to opening to the atmosphere. Emissions occur from purging the vapor space to the flare prior to opening and purging to flare during refilling of the equipment. The emissions calculations are presented in Table A-11 of Appendix A.

Section 6
Best Available Control Technology Analysis

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 emissions units associated with the project that emit GHGs include four new natural gas fired process heaters, one new and one existing natural gas fired tank heater, natural gas pipeline fugitives, one flare, two existing and one new vapor recovery units, and four emergency use diesel engines. This BACT analysis addresses these emission units.

The PSD regulations define BACT at 40 CFR § 52.21(b)(12) as follows:

> [BACT] means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.

The PSD regulations do not prescribe a procedure for conducting BACT analyses. Instead, the U.S. EPA has consistently interpreted the BACT requirement as containing two core criteria: First, the BACT analysis must include consideration of the most stringent available technologies, *i.e.*, those that provide the "maximum degree of emissions reduction." Second, any decision to require as BACT a control alternative that is less effective than the most stringent available must be justified by an analysis of objective indicators showing that energy, environmental, and economic impacts render the most stringent alternative unreasonable or otherwise not achievable. U.S. EPA has developed what it terms the "top-down" approach for conducting BACT analyses and has indicated that this approach will generally yield a BACT determination satisfying the two core criteria. Under the "top-down" approach, progressively less stringent control technologies are analyzed until a level of control considered BACT is reached, based on the environmental, energy, and economic impacts. The top-down approach was utilized in this BACT analysis.

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

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

In its *PSD and Title V Permitting Guidance for Greenhouse Gases* (November 2010), EPA reiterates that this is also the recommended process for permitting of GHG emissions under the PSD program. As such, this BACT analysis follows this 5-step approach.

6.1 Process Heaters (H-1A, H-1B, H-2A, H-2B)

The four larger gas-fired process heaters (two Hot Oil and two Fractionator Heaters) will account for about 90% of the Splitter Project GHG Emissions and are therefore the focus of the BACT analysis. All fuel fired in the heaters will be either natural gas or a small fuel gas stream with GHG emissions factors that are comparable to natural gas.

6.1.1 Step 1 – Identification of Potential Control Technologies

To maximize thermal efficiency at the Splitter, the process heaters will have a design thermal efficiency of at least 85%. These and other potentially applicable technologies to minimize GHG emissions from the heaters include the following:

- Periodic Tune-up – Periodically tune-up of the heaters to maintain optimal thermal efficiency.
- Heater Design – Good heater design including heat transfer/recovery efficiency, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss all increase overall thermal efficiency.
- Heater Air/Fuel Control – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.

- Waste Heat Recovery – Use of heat recovery from both the heater exhausts and process streams to preheat the heater combustion air, feed (oil) to heaters, or to produce steam for use at the site.
- Product Heat Recovery – Use of heat exchangers throughout the plant to recovery usable heat from product streams reduces overall energy consumption and a reduction in the amount of fuel required by heaters.
- Use of Low Carbon Fuels – Fuels vary in the amount of carbon per Btu, which in turn affects the quantity of CO_2 emissions generated per unit of heat input. Selecting low carbon fuels is a viable method of reducing GHG emissions.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

A RACT/BACT/LAER Clearinghouse (RBLC) search was also conducted in an attempt to identify BACT options that have been implemented or proposed for other similar gas fired combustion facilities. The results of this search are presented in Appendix B. No additional technologies were identified. The control methods identified in the search were limited to the first three options listed above (tune-ups, good design, and good combustion practice and operation). Information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used in the preparation of this analysis.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered technically feasible; however, waste heat recovery is not considered to be a practical alternative for the proposed heaters. The Hot Oil Heaters, although of a size sufficient enough to consider use of waste heat recovery, are designed to maximize heat transfer to the oil medium, with a resulting low exhaust gas temperature (<400 °F) that does not contain sufficient residual heat to allow any further effective heat recovery. For example, use of flue gas heat recovery to preheat the heater combustion air is typically only considered practical if the exhaust gas temperature is higher than 650 °F (*Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008)).

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

6.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel to CO_2. Fuels used in industrial processes and power generation typically include coal, fuel oil, natural gas, and process fuel gas. Of these, natural gas is typically the lowest carbon fuel that can be burned, with a CO_2 emission factor in lb/MMBtu about 55% of that of sub-bituminous coal. Process fuel gas is a byproduct of chemical process, which typically contains a higher fraction of longer chain carbon compounds than natural gas and thus results in more CO_2 emissions. Table C-2 in 40 CFR Part 98 Subpart C, which contains CO_2 emission factors for a variety of fuels, gives a CO_2 factor of 59 kg/MMBtu for fuel gas compared to 53.02 kg/MMBtu for natural gas. Of over 50 fuels identified in Table C-2, coke oven gas, with a CO_2 factor of 46.85 kg/MMBtu, is the only fuel with a lower CO_2 factor than natural gas, and is not viable fuel for the proposed heaters, as the Corpus Christi Terminal 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%. The Corpus Christi Terminal does not include any processes that produce hydrogen; therefore, hydrogen is not a viable fuel option. Natural gas is the lowest carbon fuel available for use in the proposed heaters.

CO_2 capture and storage is capable of achieving 90% reduction of produced CO_2 emissions and thus is considered to be the most effective control method. Good heater design, air/fuel ratio control, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. The estimated efficiencies were obtained from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental

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

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

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

> For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is available for large CO_2-emitting facilities including fossil fuel-fired power plants and industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing). For these types of facilities, CCS should be listed in Step 1 of a top-down BACT analysis for GHGs." The CO_2 streams included in this permit application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are dilute streams, and thus are not among the facility types for which the EPA guidance states CCS should be listed in Step 1 of a top-down BACT analysis.

Although the proposed facility is not one of the listed facility types for which CCS should be considered, it was further evaluated for the project to ensure that the analysis was complete. CCS technology has been proposed for some recent gasification projects. In these processes, when coal is gasified, the product is a mixture consisting primarily of CO, CO_2, and H_2. Further processing of the raw syngas to produce a final fuel product typically results in a concentrated CO_2 waste stream that is naturally ready for sequestration. Combustion of natural gas or ethane, as is proposed by Magellan, produces an exhaust stream that is less than 10% CO_2. Separation (purification) of the CO_2 from the heater combustion exhaust streams would require additional costly steps not otherwise necessary to the process. Coal also has a much higher carbon content than natural gas, and the captured carbon from coal gasification projects only represents the delta between natural gas and coal. Thus, while such projects may reduce GHG emissions compared to conventional methods of obtaining energy from coal, they result in no GHG emissions reduction relative to use of natural gas fuel as proposed for the process heaters.

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

Regardless of these differences, for completeness purposes, Magellan has performed an order of magnitude cost analysis for CCS applied to the four process heaters addressed in this permit application. The results of the analysis, presented in Tables 6-1 and 6-2, show that the cost of CCS for the project would be approximately $113 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 $21,000,000 per year the four heaters. The best estimate of the total capital cost of the Splitter facility without CCS is about $400,000,000. Based on a 7% interest rate, and 20 year equipment life, this cost equates to an annualized cost of $38,000,000. Thus the annualized cost of CCS is more than half of the annualized capital cost of the project 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 proposed heaters. The additional process equipment required to separate, cool, and compress the CO_2 would require a significant additional power and energy expenditure. This equipment would include amine units, cryogenic units, dehydration units, and compression facilities. The power and energy must be provided from additional combustion units, including heaters, engines, and/or combustion turbines. Electric driven compressors could be used to partially eliminate the additional emissions from the terminal itself, but significant additional GHG emissions, as well as additional criteria pollutant (NO_x, CO, VOC, PM, SO_2) emissions, would occur from the associated power plant that produces the electricity. The additional GHG emissions resulting from additional fuel combustion would either further increase the cost of the CCS system if the emissions were also captured for sequestration or reduce the net amount GHG emission reduction, making CCS even less cost effective than shown in Table 6-1.

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

Heater Design. New heaters can be designed with efficient burners, more efficient heat transfer efficiency to the hot oil and process streams, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss and increase overall thermal efficiency. The function and near steady state operation of the Hot Oil Heaters allows them to be designed to achieve “near best” thermal efficiency. There are no negative environmental, economic, or energy impacts associated with this control technology.

Air/Fuel Controls. Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and for safety reasons. More excess air than needed to achieve these objectives reduces overall heater efficiency. Manual or automated air/fuel ratio controls are used to optimizes these parameters and maximize the efficiency of the combustion process. Limiting the excess air enhances efficiency and reduces emissions through reduction of the volume of air that needs to be heated in the combustion process. In addition, proper fuel gas supply system design and operation to minimize fluctuations in fuel gas quality, maintaining sufficient residence time to complete combustion, and good burner maintenance and operation are a part of Magellan’s good combustion practices. There are no negative environmental, economic, or energy impacts associated with this control technology.

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

- Preventive maintenance check of fuel gas flow meters as needed,
- Preventive maintenance check of oxygen control analyzers as needed,
- Cleaning of burner tips on an as-needed basis, and
- Cleaning of convection section tubes on an as-needed basis.

These activities insure maximum thermal efficiency is maintained; however, it is not possible to quantify an efficiency improvement, although convection cleaning has shown improvements in the 0.5 to 1.5% range.

Product Heat Recovery. Rather than increasing heater efficiency, this technology reduces potential GHG emissions by reducing the required heater duty (fuel firing rate), which can substantially reduce overall plant energy requirements. The process includes multiple heat exchangers which reduce the heating and cooling requirements of the process leading to improved thermal efficiency. For example, the feed to the pre-flash column will be preheated by cross heat exchange with hot streams from the fractionator. Also, an overhead process vent stream will be used as a heater fuel source thus reducing the need to flare the stream and produce additional GHG emissions with no resulting energy benefit.

Use of Low Carbon Fuel. Natural gas is the lowest carbon fuel available for use in the proposed heaters. Natural gas is readily available at the Corpus Christi Terminal 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. Although use of natural gas as fuel results in about 28% less CO_2 emissions than diesel fuel and 45% less CO_2 emissions than sub-bituminous coal; Magellan believes it is appropriate to consider natural gas as the "baseline" fuel for this BACT analysis. Also note that the use of produced off-gas as supplemental fuel gas will minimize the use of purchased natural gas and lower the overall site carbon footprint.

6.1.5 Step 5 – Selection of BACT

Magellan proposes to incorporate all of the control options identified in Section 6.1.1, except carbon capture and sequestration, as BACT for controlling GHG emissions from the proposed condensate splitter process heaters. These technologies and additional BACT practices proposed for the heaters are listed below:

- Use of low carbon fuel. The proposed heaters will use natural gas fuel as it is the lowest carbon purchased fuel available for use at the facility. A small process gas stream with a composition similar to natural gas will also be used as fuel. This fuel contribution will not alter the overall GHG emissions (lb/MMbtu basis) compared to natural gas alone.
- Heater/Process Design. The heaters will be designed to maximize heat transfer efficiency and reduce heat loss.
- Periodic Heater Tune-ups. Magellan will maintain analyzers and clean heater burner tips and convection tubes as required by the vendor.
- Product Heat Recovery. Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat.
- Air to Fuel Ratio Control. Monitor exhaust temperature and O_2 content, and adjust the air/fuel using fans and a bypass damper on the air preheat exchanger to maintain heater efficiency to the maximum extent practical.

6.2 Tank Heaters (H-3, H-4)

The two tank heaters are small natural gas fired heaters that do not run continuously and constitute less the 4% of the total project GHG emissions, making consideration of most technologies to reduce GHG emissions impractical and/or of little benefit.

6.2.1 Step 1 – Identification of Potential Control Technologies

Potentially applicable technologies to minimize GHG emissions from the tank heaters include the following:

- Periodic Tune-up – Periodically tune-up of the heaters to maintain optimal thermal efficiency.
- Heater Design – Good heater design including heat transfer/recovery efficiency, state-of-the-art refractory and insulation materials in the heater walls, floor, and other surfaces to minimize heat loss all increase overall thermal efficiency.
- Heater Air/Fuel Control – Monitoring of oxygen concentration in the flue gas to be used to control air to fuel ratio on a continuous basis for optimal efficiency.
- Waste Heat Recovery – Use of heat recovery from both the heater exhausts and process streams to preheat the heater combustion air, feed (oil) to heaters, or to produce steam for use at the site.
- 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.
- Limited operation to minimize emissions.
- CO_2 Capture and Storage – Capture and compression, transport, and geologic storage of the CO_2.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

Due to the small size, intermittent operation, and minimal GHG emissions from the tank heaters, waste heat recovery and CCC are considered technically infeasible for these heaters. The tank heaters cannot be used effectively for waste heat recovery, as they are small on/off cycled heaters. For these reasons, use of waste heat recovery on the heaters was eliminated from further consideration.

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:

- Use of low carbon fuels (up to 100% for fuels containing no carbon),
- Limited operation (50% reduction based on 6 months per year of operation).
- Heater Design (up to 10%),
- Air/Fuel Control (5 - 10%),
- Periodic Tune-ups (negligible for these heaters).

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

All remaining options in Step 3 for minimizing GHG emissions are typically used to varying degrees to improve efficiency and minimize GHG emissions from all heaters, and no further evaluation of these options is considered necessary.

6.2.5 Step 5 – Selection of BACT

The following design and operating practices will be used to minimize GHG emissions from the tank heaters:

- Use of low carbon fuels natural gas as the only fuel,
- Limit operation to an average of 6 months per year for the two heaters combined.
- Efficient heater design,
- Manual air/fuel control,
- Periodic tune-ups as required by the manufacturer.

Due to the small size and insignificant amount of GHG emissions, it is not practical to implement any specific efficiency standard or metric that will be monitored or demonstrated during actual operation of the tank heaters.

6.3 Flare

GHG emissions, primarily CO_2, are generated from the flare (EPN FL-1) from the combustion of waste gas streams from the proposed units and pilot/assist natural gas used to maintain the required minimum heating value to achieve adequate destruction. Both routine and MSS flaring will occur.

6.3.1 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/vapor combustion unit (VCU) in lieu of a flare.
- Use of a vapor recovery unit (VRU) in lieu of a flare.

6.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

One of the primary reasons that a flare is consider for control of VOC in the process vent streams is that it can also be used for emergency releases. Although every possible effort is made to prevent such releases, they can occur, and the design must allow for them. A thermal oxidizer/VCU is not capable of handling the sudden large volumes of vapor that could occur during an upset release. A thermal oxidizer/VCU would also not result in a significant difference in GHG emissions compared to a flare. The same constraints exist with a VRU. For this reason, even if a thermal oxidizer/VCU or a VRU 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, complete elimination of the flare and use of either a thermal oxidizer/VCU or VRU is rejected as technically infeasible for the project.

6.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- Flaring minimization (up to 100% GHG emission reduction); and
- Proper operation of the flare (not directly quantifiable).

Virtually all GHG emissions from fuel combustion result from the conversion of the carbon in the fuel and/or waste gas to CO_2. The proposed condensate splitter process will be designed to minimize the volume of gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. Flaring will be limited to purge/pilot gas and vapors from emission events and MSS activities. Proper operation of the flare results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

Flaring Minimization: The proposed process condensate splitter plant will be designed to minimize the volume of gas sent to the flare. During routine operation, gas flow to the flare will be limited to pilot and purge gas only. Process/waste gases from the proposed condensate splitter plant will be recycled back to the heaters as heat input thus reducing the amount of nature gas heat input. This control technology goes not cause any negative environmental, economic, or energy impacts.

Proper Operation of the Flare: The flare will be equipped with continuous pilot flame monitoring and a thermocouple on the flare stack. Magellan will adjust the amount of assist natural gas as needed for proper operation of the flare. This ensures proper destruction of VOCs and that excess natural gas is not unnecessarily flared. The destruction efficiency is 99% for VOC compounds containing no more than 3 carbons that contain no elements other than carbon and hydrogen in addition to the following compounds: methanol, ethanol, propanol, ethylene oxide, and propylene oxide. The destruction efficiency is 98% for other VOC compounds. This control option is also cost effective as both a criteria pollutant and GHG emission control option because it reduces fuel consumption. This control technology goes not cause any negative environmental, economic, or energy impacts.

6.3.5 Step 5 – Selection of BACT

Magellan proposes to incorporate all of the control options identified in Section 6.3.1, except for utilizing a thermal oxidizer, VCU, or VRU in lieu of the flare, as BACT for controlling GHG emissions from flaring. These technologies are listed below:

- *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:* Equip the flare with continuous pilot flame monitoring, a thermocouple on the flare stack, and maintain a minimum heating value of 300 Btu/scf. The flare purge rate will be determined by the manufacturer. Visual opacity monitoring will occur when the flare is operating.

6.4 Natural Gas Piping Fugitives

Small amounts of methane emissions may occur from leaking natural gas piping components associated with the proposed project and thus contribute a small amount to the total project GHG emissions.

6.4.1 Step 1 – Identification of Potential Control Technologies

A search of the RACT/BACT/LAER Clearinghouse (RBLC) database and permit applications that have been submitted to EPA Region 6 for fugitive emissions from natural gas piping fugitives was conducted to determine possible BACT technologies.

Based on these searches, the following available control technologies were identified:

- Install leakless technology components to eliminate fugitive emission sources; and
- Implement an instrument-based LDAR program.
- Implement an audio, visual, olfactory (AVO) LDAR program.

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 are considered “technically” feasible.

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Leakless components - By installing leak free valves and piping systems the site could achieve close to 100% reduction in GHG (methane) emissions from leaking valves in natural gas service.

Instrument-based LDAR program – An instrument-based LDAR program could control GHG fugitive emissions by 75% or more.

AVO LDAR program – An AVO LDAR program could control GHG fugitive emissions by 75% or more.

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

Leakless components - Leakless technology components are available and currently in use in operations that produce or use highly toxic materials. These operations represent a serious threat to human health from even the smallest amount of fugitive emissions; therefore, leakless technology is a practical cost effective technology to use in highly toxic environments. These technologies have not been incorporated as BACT into the designs of natural gas pipeline fugitives since they are not considered to be highly toxic emissions. Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions. Any further consideration of available leakless technologies for GHG controls is not appropriate; therefore, this control is rejected from further consideration.

Instrument-Based LDAR program – Although technically feasible, use of an LDAR program to control the negligible amount of GHG emissions that may occur from the proposed natural gas fugitives is clearly not cost effective due to the already insignificant level of emissions. However, a cost effectiveness analysis for a basic LDAR program to control process fugitive CH_4 emissions is presented in Table 6-3 to demonstrate this point. The analysis shows that even the least stringent LDAR program (TCEQ's 28M program) would cost $1163/ton of CH_4 controlled ($47/ton of CO_2e controlled). This cost is considered excessive for GHGs. The primary purpose of implementing an LDAR program as BACT is to control fugitive emissions of VOCs to the atmosphere. Because natural gas does not contain a significant amount of VOC, an LDAR program on components in this service would have a negligible impact on VOC emissions and is thus not necessary for VOC BACT purposes. Since LDAR is not being implemented at the site for natural gas components as a VOC control practice, and the cost of the program to control GHG emissions alone would be excessive, Magellan rejected LDAR from further consideration.

AVO LDAR program – An AVO program is technically feasible and of minimal cost if conducted by plant personnel; therefore, a cost analysis has not been performed. There are also no negative energy and environmental impacts associated with such a program.

6.4.5 Step 5 – Selection of BACT

Due to the negligible amount of GHG emissions from natural gas piping fugitives, implementation of an LDAR program or installing leakless components is clearly not cost effective and would result in no significant reduction in overall project GHG emissions. An AVO LDAR program conducted by plant personnel is a cost effective means of providing control of leaks and reducing GHG emissions. Based on these considerations, BACT for the natural gas fugitive emissions is determined to be use of high engineering standards for the selection of equipment and implementing an AVO LDAR program by plant personnel. The AVO program will consist of daily AVO inspections of all natural gas piping components to identify leaks. Any leaks that are found will be repaired as soon as practical, but no later than 30 days following identification of the leak. Records of inspections, identified leaks, and repairs will be maintained at the plant.

6.5 Marine VCUs

Vapors generated by marine loading products with a vapor pressure of 0.5 psia or greater from the proposed condensate splitter are controlled by the marine VCUs. Assist natural gas is used to maintain the combustion chamber temperature necessary to achieve adequate destruction. The combustion of loading vapors and natural gas generate GHG emissions.

6.5.1 Step 1– Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions associated with control of loading vapors is minimizing the quantity of combusted VOC vapors and natural gas. The available control technologies for barge and ship loading emissions are:

- *Use of a flare in lieu of a thermal oxidizer/VCU:* Alternate control technology consideration.
- *Use of a VRU in lieu of a VCU:* Alternate control technology consideration.
- *Minimization:* Minimize the duration and quantity of combustion through good engineering design of the process and good operating practice.
- *Proper operation of the VCU:* Use of a temperature monitor to ensure adequate VOC destruction in order to minimize natural gas combustion and resulting GHG emissions.

6.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

VCUs typically achieve higher DREs (99% or greater) than flares (98%); therefore, VCUs are often utilized to control loading emissions as constituting LAER. Also, the use of a flare would not result in a significant difference in GHG emissions compared to a thermal oxidizer/VCU. Vapor recovery units are not technically feasible for this project because the control devices are located at the shared Port of Corpus Christi docks, and the availability of necessary utilities and space to construct new VRUs is limited.

For these reasons, the use of vapor recovery unit are rejected as technically infeasible for control of marine loading vapors in this instance. Both minimization and proper operation of the VCU are technically feasible. A flare is also technically feasible, but would result in higher VOC emissions with no significant difference in GHG emissions.

6.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

- Minimization (up to 80% GHG emission reduction associated with submerged loading of ships and barges, 100% GHG emission reduction due to pressurized truck loading); and
- Proper operation of the VCU (not directly quantifiable).
- Flaring of marine loading vapors would result in higher VOC emissions and no improvement in GHGs.

Virtually all GHG emissions from fuel combustion result from the conversion of carbon in the fuel to CO_2. The proposed marine loading operations from the condensate splitter process will be designed to minimize the volume of the gas sent to the VCU. Specifically, the use of submerged loading leads to a vapor space concentration reduction of up to 80% during ship loading activities or 50% during barge loading activities.

Proper operation of the VCU results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. Use of an analyzer(s) to determine the VCU combustion chamber temperature allows for the continuous determination of the amount of natural gas needed to maintain the combustion chamber above 1,400 °F or the most recent stack test temperature (e.g., 1350 °F from 2013 test). Maintaining the combustion chamber above the minimum temperature maintains proper destruction of VOCs and ensures that excess natural gas is not unnecessarily combusted.

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

Minimization: The loading operations related to the condensate splitter process will be designed to minimize the volume of gas sent to the VCU. Specifically, submerged and/or pressurized loading reduces the volume of waste gas generated during the loading process which in turn reduces GHG emissions associated with loading VOC vapor control. There are no negative environmental, economic, or energy impacts associated with this control technology.

Proper Operation of the VCU: Analyzer(s) will be used to ensure that the VCU combustion chamber temperature remains above 1,400 °F or the most recent stack test temperature in accordance with Special Condition No. 16 of NSR Permit No. 56470. The temperature will be measured and recorded with 6 minute averaging periods as required by the NSR permit. Maintaining the VCU combustion chamber at the proper temperature for the destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. The 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, economic, or energy impacts associated with this control technology.

6.5.5 Step 5 – Selection of BACT

Magellan proposes to incorporate all of the control options identified in Section 6.5.1, except for utilizing a thermal oxidizer, flare, or VRU in lieu of the VCU, as BACT for controlling GHG emissions from loading. These technologies are listed below:

- *Minimization:* Minimize the duration and quantity of combustion to the extent possible through good engineering design of the process and good operating practice.
- *Proper operation of the VCU:* Use of temperature monitoring to ensure VOC destruction in order to minimize natural gas combustion and resulting CO_2 emissions.

6.6 Diesel Engines

The diesel engines will be used for emergency purposes only, and the only non-emergency operation will be for testing no more than 100 hours per year.

6.6.1 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.

6.6.2 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.

6.6.3 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.

6.6.4 Step 4 – Evaluation of Control Technologies in Order of Most 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.

6.6.5 Step 5 – Selection of BACT

Magellan 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 100 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.

6.7 MSS Emissions

GHG emissions, primarily CO_2, are generated from the combustion of VOC vapors associated with MSS activities (storage tank roof landings, pressure sphere clearing, and purging of vessels and piping) for the proposed condensate splitter plant and assist natural gas used to maintain the required minimum heating value or combustion chamber temperature to achieve adequate destruction. Magellan plans to use a flare (FL-1) and a VCU (MSSVCU) for control of MSS emissions. The MSS VCU will also control emission from the wastewater treatment system, which will result in a minimal amount of additional CO_2 emissions.

6.7.1 Step 1 – Identification of Potential Control Technologies

The only viable control option for reducing GHG emissions associated with MSS vapor control is minimizing the quantity of combusted VOC vapors and natural gas to the extent possible. The available control technologies for MSS emissions are:

- Use of non-combustion control devices in lieu of a flare/VCU: Carbon canisters and scrubbers do not generate GHG emissions and will be utilized to control MSS emissions associated with vacuum trucks, frac tanks, etc.
- Minimization: Minimize the duration and quantity of combustion to the extent possible through good engineering design of the storage tanks and process equipment and good operating practice.
- Proper operation of the flare/VCU: Use of monitors to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and resulting CO_2 emissions.

6.7.2 Step 2 – Elimination of Technically Infeasible Alternatives

The use of a carbon canisters, scrubbers, minimization, and proper operation of the flare/VCU are considered technically feasible.

6.7.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The technologies applicable to MSS activities in order of most effective to least effective include:

- Use of a carbon canisters and/or scrubbers in lieu of a flare/VCU (up to 100% GHG emission reduction);
- Minimization (not directly quantifiable for MSS activities); and
- Proper operation of the flare/VCU (not directly quantifiable for MSS activities).

Proper operation of carbon canisters and scrubbers for MSS VOC emissions control results in a GHG emission reductions up to 100%. Fuel and/or waste gas combustion which results in the conversion of carbon in the fuel and/or waste gas to CO_2 does not occur with these devices.

The proposed process condensate splitter plant will be designed to minimize the volume of the waste gas sent to the control device. These improvements cannot be directly quantified; therefore, the above ranking is approximate only. Waste gas volumes will be reduced by minimizing storage tank vapor space volumes requiring control during MSS activities (i.e., degassing, etc.). Proper operation of the flare or VCU results in a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only.

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

Use of a Carbon Canister and Scrubbers. Carbon canisters and scrubbers could be used for control of MSS VOC emissions from vacuum trucks, frac tanks, etc. The applicability of these control methods is limited based on flow rates and event duration. These devices are not capable of handling the sudden large volumes of vapor that could occur during unit turnarounds or storage tank roof landing activities. There are no negative environmental, economic, or energy impacts associated with this control technology.

Minimization. New storage tanks and process equipment are designed such that the vapor space volume requiring control during MSS activities is minimized. Specifically, VOC emissions and the subsequent GHG emissions associated with MSS activities are significantly reduced by limiting the duration of MSS activities, reducing vapor space volume requiring control, painting tanks white, incorporating "drain dry" sumps into the tank design, draining residual VOC material to closed systems, etc. There are no negative environmental, economic, or energy impacts associated with this control technology.

Proper Operation. Managing the flare waste gas stream and VCU operation for the proper destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. This added advantage of reducing fuel consumption makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental, economic, or energy impacts associated with this control technology.

6.7.5 Step 5 – Selection of BACT

Magellan proposes to incorporate the remaining control options identified in Section 6.7.1 as BACT or controlling GHG MSS emissions from the proposed condensate splitter plant. These technologies proposed for MSS activities are listed below:

- *Use of a carbon canisters and/or scrubbers*. Carbon canisters and/or scrubbers will be utilized to control MSS emissions associated with vacuum trucks, frac tanks, etc.
- *Minimization.* Minimize the duration and quantity of combustion to the extent possible through good engineering design of the storage tanks and process equipment and good operating practice.
- *Proper operation of the flare.* Equip the flare with continuous pilot flame monitoring, a thermocouple on the flare stack, and maintain a minimum heating value of 300 Btu/scf.
- *Proper Operation of the VCU.* Continuous temperature monitoring, (during use) to accurately determine the optimum amount of natural gas required to maintain adequate VOC destruction in order to minimize natural gas combustion and resulting CO_2 emissions.

Table 6-1 Cost Analysis for Post-Combustion CCS Process Heaters

CCS System Component	Cost ($/ton of CO_2 Controlled)[1]	Tons of CO_2 Controlled per Year[2]	Total Annualized Cost ($/yr)
CO_2 Capture and Compression Facilities	$103	188,139	$19,378,270
CO_2 Transport Facilities (Table 6-2)	$4.76	188,139	$896,319
CO_2 Storage Facilities[3]	$5.41	188,139	$1,017,964
Total CCS System Cost	$113	188,139	$21,292,553
Proposed Plant Cost	**Total Capital Cost[4]**	**Capital Recovery Factor[5]**	**Annualized Capital Cost ($/yr)**
Cost of Proposed Project w/o CCS	$400,000,000	0.0944	$37,757,170

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 four process heaters.

3: Storage Cost ($/tonne, converted to $/ton) from: *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport* and Storage Costs, National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2013/1614, March 2013.

4. Capital cost of Condensate Splitter Project is estimated to be $300,000,000 to $400,000,000. Upper end of range is used in this analysis.

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

Interest rate	7%
Equipment Life (yrs)	20

Table 6-2 CO_2 Pipeline Construction Cost Estimate

Description	Cost	Basis
Capital Cost:		
CO_2 Pipeline - 10" Diameter	$8,000,000	10-mile pipeline 10-inch diameter (10 miles is location of nearest pipeline or storage cavern). DOE/NETL calculation method (see below).
CO_2 Surge Tank and Pipeline Control System	$600,000	Estimate from DOE/NETL[2] method, scaled back for smaller system
Total Capital Cost for CO2 Compression, Pipeline, and Well	**$8,600,000**	
Capital Recovery Factor[1]	0.0944	7% interest rate and 20 year equipment life
Annualized Capital Cost ($/yr)	**$811,779**	Total capital cost times capital recovery factor
Operating Cost:		
O&M Cost, $/year	$84,540	O&M $8,454/mile/yr[2]
Total Annual Operating Cost ($/yr)	**$84,540**	
Total Cost:		
Total Annual Cost ($/yr)	**$896,319**	Annualized capital cost plus annual operating cost
GHG Emissions Controlled (ton/yr)	188,139	From GHG Calculations in Appendix A
Cost ($/ton)	**$4.76**	Total Annual Cost/GHG Emissions Controlled

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

Interest rate: 7%
Equipment Life (yrs): 20

Capital Cost for Construction of CO2 Pipeline to Nearest Storage Cavern:

Length in miles (L): 10
Diameter in inches (D): 10

Several candidate storage reservoirs exist within 10 to 50 miles of the proposed project; however, none of these have been confirmed to be viable for large scale CO2 storage at this time. However, it was assumed for this analysis that a suitable storage reservoir would be available within 10 miles.

Component	**Cost**	**Cost Equation**[2]
Materials	$1,414,578	Materials = $70,350 + $2.01 x L x (330.5 x D^2 + 686.7 x D + 26,960)
Labor	$4,895,817	Labor = $371,850 + $2.01 x L x (343.2 x D^2 + 2,074 x D + 170,013)
Miscellaneous	$1,564,012	Misc. = $147,250 + $1.55 x L x (8,417 x D + 7,234)
Right-of-Way	$506,342	Right-of-Way = $51,200 + $1.28 x L x (577 x D + 29,788)
Total Cost of Pipeline	**$8,380,749**	

2: Pipeline cost equations are from: *Quality Guidelines for Energy System Studies: Estimating Carbon Dioxide Transport and Storage Costs* , National Energy Technology Laboratory, U.S. Dept. of Energy, DOE/NETL-2013/1614, March 2013.

Table 6-3 Cost Analysis for Natural Gas Fugitives LDAR Program

Monitoring Cost:	$2.50	per component per quarter
Number of Valves:	200	monitored
Number of Flanges:	1,407	(walk through monitoring)
Number of PRVs:	0	monitored
Number of Pumps:	0	monitored
Number of Comps:	0	monitored
Total Number Monitored:	200	monitored
Total Cost of Monitoring:	$2,000	per year
Number of Repairs:	64	per year (8% of monitored components per quarter)
Cost of Repairs:	$10,880	per year @ $200 per component (85% of leaking components; remaining 15% only require minor repair)
Cost to re-monitor repairs:	$160	per year
Total Cost of LDAR:	$13,040	per year (monitoring + repair + re-monitor)
CH_4 Uncontrolled:	25.7	tpy of CH_4
CO_2e Uncontrolled:	641.7	tpy of CO_2e
CH_4 Controlled:	14.5	tpy of CH_4
CO_2e Controlled:	361.5	tpy of CO_2e
CH_4 Emission Reduction:	11.2	tpy of CH_4
CO_2e Emission Reduction:	280.2	tpy of CO_2e
CH_4 Cost Effectiveness:	**$1,163**	per ton of CH_4
CO_2e Cost Effectiveness:	**$47**	per ton of CO_2e

Appendix A

Emission Calculations

Table A-1
Heater Emissions
Magellan Corpus Christi Splitter Project
August 2014

Source	Pollutant	Annual Average Firing Rate (MMBtu/hr)	Maximum Firing Rate (MMBtu/hr)	Annual Operation (hours)	Annual Emission Factor (lb/MMBtu)	Emissions (tpy)	Emission Factor Basis	GWP	CO2e Emissions (tpy)
Fractionator Heater H-1A	CO2	149	164	8,760	1.17E+02	76,341.62	40 CFR 98 Tables C-1 and C-2.	1	**76,341.62**
	N2O				2.20E-04	0.14	40 CFR 98 Tables C-1 and C-2.	298	**42.88**
	CH4				2.20E-03	1.44	40 CFR 98 Tables C-1 and C-2.	25	**35.97**
Hot Oil Heater H-1B	CO2	55	61	8,760	1.17E+02	28,179.79	40 CFR 98 Tables C-1 and C-2.	1	**28,179.79**
	N2O				2.20E-04	0.05	40 CFR 98 Tables C-1 and C-2.	298	**15.83**
	CH4				2.20E-03	0.53	40 CFR 98 Tables C-1 and C-2.	25	**13.28**
Fractionator Heater H-2A	CO2	149	164	8,760	1.17E+02	76,341.62	40 CFR 98 Tables C-1 and C-2.	1	**76,341.62**
	N2O				2.20E-04	0.14	40 CFR 98 Tables C-1 and C-2.	298	**42.88**
	CH4				2.20E-03	1.44	40 CFR 98 Tables C-1 and C-2.	25	**35.97**
Hot Oil Heater H-2B	CO2	55	61	8,760	1.17E+02	28,179.79	40 CFR 98 Tables C-1 and C-2.	1	**28,179.79**
	N2O				2.20E-04	0.05	40 CFR 98 Tables C-1 and C-2.	298	**15.83**
	CH4				2.20E-03	0.53	40 CFR 98 Tables C-1 and C-2.	25	**13.28**
Tank Heater H-3	CO2	16	16	4,380	1.17E+02	4098.88	40 CFR 98 Tables C-1 and C-2.	1	**4,098.88**
	N2O				2.20E-04	0.01	40 CFR 98 Tables C-1 and C-2.	298	**2.30**
	CH4				2.20E-03	0.08	40 CFR 98 Tables C-1 and C-2.	25	**1.93**
Tank Heater H-4	CO2	16	15	4,380	1.17E+02	4098.88	40 CFR 98 Tables C-1 and C-2.	1	**4,098.88**
	N2O				2.20E-04	0.01	40 CFR 98 Tables C-1 and C-2.	298	**2.30**
	CH4				2.20E-03	0.08	40 CFR 98 Tables C-1 and C-2.	25	**1.93**

Notes:
1. Emission factors from 40 CFR 98, Tables C-1 and C-2.
2. Global warming potential factors from 40 CFR 98, Table A-1.

Table A-1a

CO_2 Emission factor Calculation for non-condensible gas to be used as heater fuel

Magellan Corpus Christi Splitter Project

April 2014

Component		MW	Reported	Normalized	Normalized	Specific Volume	Higher Heating Value [1]		Lower Heating Value [1]	
		[lb/lbmol]	mole %	mole %	weight %	[ft^3/lb]	Btu/lbm	Btu/ft^3	Btu/lbm	Btu/ft^3
Nitrogen	N_2	28.01	0.000	0.000	0.000	13.55	0	0	0	0
Carbon Dioxide	CO_2	44.01	0.000	0.000	0.000	8.63		0	0	0
Carbon Monoxide	CO	28.01	0.000	0.000	0.000	13.55	4,342.0	320.5	4,342.0	320.5
Helium	He	4.00	0.000	0.000	0.000	94.84	0.0	0.0	0.0	0.0
Argon	Ar	39.95	0.000	0.000	0.000	9.50	0.0	0.0	0.0	0.0
Hydrogen	H_2	2.02	0.000	0.000	0.000	188.33	61,022.0	324.2	51,566.0	273.9
Methane	CH_4	16.04	87.650	87.650	73.429	23.66	23,891.0	1,010.0	21,511.0	909.4
Ethane	C_2H_6	30.07	8.290	8.290	13.017	12.63	22,333.0	1,769.7	20,429.0	1,618.7
Propane	C_3H_8	44.10	0.000	0.000	0.000	8.61	21,653.0	2,516.1	19,922.0	2,314.9
Iso-Butane	C_4H_{10}	58.12	0.110	0.110	0.334	6.53	21,232.0	3,251.9	19,590.0	3,000.4
n-Butane	C_4H_{10}	58.12	2.270	2.270	6.890	6.53	21,300.0	3,262.3	19,658.0	3,010.8
Iso-Pentane	C_5H_{12}	72.15	1.680	1.680	6.330	5.26	21,043.0	4,000.9	19,456.0	3,699.0
n-Pentane	C_5H_{12}	72.15	0.000	0.000	0.000	5.26	21,085.0	4,008.9	19,481.0	3,703.9
n-Hexane	C_6H_{14}	86.18	0.000	0.000	0.000	4.41	20,943.0	4,755.9	19,393.0	4,403.9
n-Heptane	C_7H_{16}	100.20	0.000	0.000	0.000	3.79	20,839.0	5,502.5	19,315.0	5,100.3
Ethylene	C_2H_4	28.05	0.000	0.000	0.000	13.53	21,640.0	1,600.0	20,278.0	1,499.0
Propylene	C_3H_6	42.08	0.000	0.000	0.000	9.02	21,039.0	2,333.0	19,678.0	2,182.0
neo-Pentane	C_5H_{12}	72.15	0.000	0.000	0.000	5.26	20,958.0	3,985.0	19,371.0	3,683.0
Acetylene	C_2H_2	26.04	0.000	0.000	0.000	14.58	23,000.0	1,600.0	21,000.0	1,450.0
Hydrogen Sulfide	H_2S	34.00	0.000	0.000	0.000	11.17	7,479	672	6,800	611
Oxygen	O_2	32.00	0.000	0.000	0.000	11.86	0	0	0	0
Water	H_2O	18.02	0.000	0.000	0.000	21.07	1,059.8	50.3	0	0
Total			**100.00**	**100.00**	**100.00**		**23,321**	**1,176.8**	**21,106**	**1,065.1**
Molecular Weight [lb/lbmol]			19.15	19.15						
HHV/LHV Ratio							1.105	1.105		

Combustion Calculations

Component		Fuel Molar Flow Rate (lbmol/mmbtu)	O2 Stoic. Coeff.	Oxygen Requirement (lbmol/mmbtu)	CO2 Stoic. Coeff.	CO2 Production (lbmol/mmbtu)	H2O Stoic. Coeff.	H2O Production (lbmol/mmbtu)
Nitrogen	N_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Carbon Dioxide	CO_2	0.000	0.000	0.000	1.000	0.000	0.000	0.000
Carbon Monoxide	CO	0.000	0.500	0.000	1.000	0.000	0.000	0.000
Helium	He	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Argon	Ar	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Hydrogen	H_2	0.000	0.500	0.000	0.000	0.000	1.000	0.000
Methane	CH_4	1.963	2.000	3.925	1.000	1.963	2.000	3.925
Ethane	C_2H_6	0.186	3.500	0.650	2.000	0.371	3.000	0.557
Propane	C_3H_8	0.000	5.000	0.000	3.000	0.000	4.000	0.000
Iso-Butane	C_4H_{10}	0.002	6.500	0.016	4.000	0.010	5.000	0.012
n-Butane	C_4H_{10}	0.051	6.500	0.330	4.000	0.203	5.000	0.254
Iso-Pentane	C_5H_{12}	0.038	8.000	0.301	5.000	0.188	6.000	0.226
n-Pentane	C_5H_{12}	0.000	8.000	0.000	5.000	0.000	6.000	0.000
n-Hexane	C_6H_{14}	0.000	9.500	0.000	6.000	0.000	7.000	0.000
n-Heptane	C_7H_{16}	0.000	11.000	0.000	7.000	0.000	8.000	0.000
Ethylene	C_2H_4	0.000	3.000	0.000	2.000	0.000	2.000	0.000
Propylene	C_3H_6	0.000	4.500	0.000	3.000	0.000	3.000	0.000
neo-Pentane	C_5H_{12}	0.000	8.000	0.000	5.000	0.000	6.000	0.000
Acetylene	C_2H_2	0.000	2.500	0.000	2.000	0.000	1.000	0.000
Hydrogen Sulfide	H_2S	0.000	1.500	0.000	0.000	0.000	1.000	0.000
Oxygen	O_2	0.000	0.000	0.000	0.000	0.000	0.000	0.000
Water	H_2O	0.000	0.000	0.000	0.000	0.000	1.000	0.000
Total		2.239		5.223		**2.735**		4.975

CO2 Emission Factor = 2.735 lbmol/mmbtu x 44.01 lb/lbmol = $\boxed{\textbf{120.38 lb/mmbtu}}$

Table A-2
Marine Loading Vapors to VCU
Magellan Corpus Christi Splitter Project
August 2014

Basis
- Emissions calculated based on loading loss factors (Tables 5.2-1, AP-42, Section 5.2).
- Saturation factor assumed to be 0.2 (ships) and 0.5 (barges), submerged loading.
- VP based on maximum expected liquid temperature for the short-term and annual average liquid temperature for the annual basis.
- Annual throughputs listed are for the purposes of estimating the emission cap only and are not meant to be operational limits.
- High VP Group includes condensate, light naphtha, and heavy naphtha. Low VP Group includes jet fuel and distillate.
- Light Naphtha temperature will be controlled to ensure that the TVP does not exceed 11 psia.

Material	Vessel Type	Collection Efficiency* (%)	Control Efficiency (%)	MW	Avg. Temp (°F)	Avg. VP (psia)	Annual Avg. Loading Loss Factor (lb/1000 gal)	Throughput (bbl/yr)	Vapors to VCU1/VCU2 tpy
High VP Group	Barge	100%	99.50%	58.7	80	11.00	7.4550	13,249,500	2074.27
High VP Group	Ship	95%	99.50%	58.7	80	11.00	2.9820	13,249,500	788.22
								Maximum**	**2074.27**

*Annual Emissions to VCU based on maximum of barge or ship.

Table A-3
Marine Loading Control - Vapor Combustor
Magellan Corpus Christi Splitter Project
August 2014

Basis

- Assumed all products have a maximum heat content equivalent to 20,000 Btu/lb.
- Total heat release values for the VCU include contributions from both the loading vapors and the added natural gas.
- VOC Destruction efficiency of VCU : 99.50%

Natural Gas Usage:		
	60,000	scf/hr
	77,745,000	scf/yr
	1,050	btu/scf, HHV

Operation Type	Annual		
	Loading Vapor tpy (from A-2)	Loading Vapors lb/yr	Total Heat Release MMBtu/yr
Barge/Ship Loading	2074.27	4,148,544	164,603.12

Operation Type	Annual	
	Loading Vapors MMBtu/yr	Natural Gas MMBtu/yr
Barge/Ship Loading	82,971	81,632.25

Combusted Material	Pollutant	Emissions Factor[1]		Emissions	GWP[2]	CO2e
		(Value)	(Units)	(ton/yr)		(ton/yr)
Natural Gas	CO_2	53.06	kg/MMBtu	4,774.55	1	4774.55
	CH_4	0.001	kg/MMBtu	0.09	25	2.25
	N_2O	0.0001	kg/MMBtu	0.01	298	2.68
Loaded Material	CO_2	74.54	kg/MMBtu	6,817.40	1	6817.40
	CH_4	0.003	kg/MMBtu	0.27	25	6.86
	N_2O	0.0006	kg/MMBtu	0.05	298	16.35

Notes:

1. Emission factors from 40 CFR 98, Tables C-1 and C-2. Loading vapor emissions calculated using crude oil factors.
2. Global warming potential factors from 40 CFR 98, Table A-1.
3. Natural Gas (MMBtu/yr) = pilot gas flow rate (scf/hr) x natural gas heat content (1,050 But/scf) x (1 MMBtu / 10^6 Btu) x (8,760 hr/yr)

Table A-5
Fugitive Component Emissions - Natural Gas (CH4) Service
Magellan Corpus Christi Splitter Project
August 2014

Basis

- Component counts are a design estimate, assumed to be 100% CH_4.
- TCEQ emission factors for the category "SOCMI without ethylene" were applied.

Component Type	Component Type	Emission Factor SOCMI Without C2	Number of Components	Uncontrolled Emissions (tpy)	AVO LDAR Control Efficiency[1]	Controlled Emissions (tpy)
Valves	Gas/Vapor	0.0089	200	7.80	75%	1.95
Flanges	Gas/Vapor	0.0029	1,407	17.87	75%	4.47
			Total Fugitive CH4 Emissions:	**25.67**		**6.42**
			Total CO2e Emissions:	**641.70**		**160.43**

1. Range of control efficency is estimated to be 75% to 97%. Low end of range is used for conservatism.

Table A-4
Flare Pilot Emissions
Magellan Corpus Christi Splitter Project
August 2014

Basis

- The only routine emissions from the flare are from the combustion of pilot gas, purge gas, and intermittent flow from the push/pull arrangement for vapor control on VC-2001 Feed Surge Drum.
- The flare may be used for emergency situations; however, those emissions are not estimated because TCEQ does not permit upsets.

Pilot Gas Flow:	163	scfh
Pilot Gas Flow:	1,423,500	scf/yr
Pilot Gas Heat Value:	1,050	Btu/scf

Purge Gas Flow:	46	scfh
Purge Gas Flow:	405,150	scf/yr
Purge Gas Heat Value:	1,050	Btu/scf

VC-2001 Feed Surge Drum Vapor Control Flow:	23.69	scfh
VC-2001 Feed Surge Drum Vapor Control Flow:	103,751	scf/yr
VC-2001 Feed Surge Drum Vapor Heat Value:	1,050	Btu/scf

Combusted Material	Pollutant	Emissions Factor[1] (Value)	Emissions Factor[1] (Units)	Emissions (ton/yr)	GWP[2]	CO2e (ton/yr)
Natural Gas	CO_2	53.06	kg/MMBtu	125.05	1	125.05
	CH_4	0.001	kg/MMBtu	0.0024	25	0.06
	N_2O	0.0001	kg/MMBtu	0.0002	298	0.07

Notes:
1. Emission factors from 40 CFR 98, Tables C-1 and C-2.
2. Global warming potential factors from 40 CFR 98, Table A-1.

Table A-6
Emergency Use Combustion Devices
Magellan Corpus Christi Splitter Project
August 2014

Diesel Fire Water Pump Engines

Basis:
- The fire water pumps will be Clarke engines model JX6H-UFAD88.

Unit ID	Pollutant	Power (hp)	Fuel Consumption (Btu/hr)	Annual Operation (hr)	Emissions Factor		Emissions	GWP[2]	CO2e
					Value	Units	tpy		tpy
FWP1	CO_2	617	3,965,000	100	73.96	kg/MMBtu	32	1	32.33
	CH_4				0.003	kg/MMBtu	1.3E-03	25	0.03
	N_2O				0.0006	kg/MMBtu	2.6E-04	298	0.08
FWP2	CO_2	617	3,965,000	100	73.96	kg/MMBtu	32	1	32.33
	CH_4				0.003	kg/MMBtu	1.3E-03	25	0.03
	N_2O				0.0006	kg/MMBtu	2.6E-04	298	0.08

Emergency Generators

Basis:
- The fire water pumps will be Caterpillar generators. The 500 kW unit is set DM8155. The 100 kW unit set P3362A.

Unit ID	Pollutant	Power (kW)	Fuel Consumption (Btu/hr)	Annual Operation (hr)	Emissions Factor		Emissions	GWP[2]	CO2e
					Value	Units	tpy		tpy
EMGEN1	CO_2	500	4,758,000	100	73.96	kg/MMBtu	39	1	38.79
	CH_4				0.003	kg/MMBtu	1.6E-03	25	0.04
	N_2O				0.0006	kg/MMBtu	3.1E-04	298	0.09
EMGEN2	CO_2	100	936,000	100	73.96	kg/MMBtu	8	1	7.63
	CH_4				0.003	kg/MMBtu	3.1E-04	25	0.01
	N_2O				0.0006	kg/MMBtu	6.2E-05	298	0.02

Table A-7
Maintenance, Startup, and Shutdown Emission Summary
Magellan Corpus Christi Splitter Project
August 2014

Source	FIN	EPN	CO_2		CH_4		N_2O	
			tpy	CO_2e tpy	tpy	CO_2e tpy	tpy	CO_2e tpy
Vessels & Piping MSS to Flare	FL-1	FL-1	450.83	450.83	0.02	0.45	0.004	1.08
IFR Tank Landings to VCU*	MSSVCU	MSSVCU	334.00	334.00	0.01	0.34	0.003	0.80
Pressure Tank MSS to VCU	MSSVCU	MSSVCU	48.89	48.89	0.002	0.059	0.0005	0.14
WWT Separator & Desalter to VCU	MSSVCU	MSSVCU	109.96	109.96	0.00E+00	0.00	0.00E+00	0.00
Assist Natural Gas in VCU	MSSVCU	MSSVCU	3,227.87	3,227.87	0.06	1.52	0.01	1.81
MSSVCU Total	MSSVCU	MSSVCU	3,720.72	3,720.72	0.08	1.92	0.01	2.76
Total MSS Emissions			**4,171.55**	**4,171.55**	**0.09**	**2.37**	**0.01**	**3.84**

*Includes both routine and MSS landings.

Table A-8a
Storage Tank Emission Calculations - Low Leg Landings, High Vapor Pressure Material (includes both routine and MSS landings)
Magellan Corpus Christi Splitter Project
August 2014

Constants			
Atmospheric Pressure	Pa	psia	14.70
Control Device			VCU
Control Device Efficiency	CE		99%

		Tank EPN	T120	T121	T122	T123	T124	T125	T135	T136	T137	T138	T139	T154	T155	T156	T157	T158	T159	T160	T161
Type			IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR
Diameter	D	ft	120	120	120	120	120	120	145	145	145	145	145	125	125	125	125	125	125	125	125
Landed Roof Leg Height		ft	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Month of Landing Event			July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July
Max Daily Ambient Temperature	T_{MAX}	deg F	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30
Min Daily Ambient Temperature	T_{MIN}	deg F	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80
Daily Total Solar Insulation Factor	I	Btu/(ft2*day)	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38
Daily Average Ambient Temperature	T_{AA}	deg R	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65
Average ambient wind speed	v	mph	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Days Off-Float (before degas/clean)	n_d	day	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Tank Heel Status [1]			Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain
Height of Liquid Heel	h_{le}	ft	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Product Stored			Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate
Vapor Molecular Wt.	M_V	lb/lbmole	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
Liquid Molecular Wt.	M_L	lb/lbmole	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9
Liquid Density	W_l	lb/gal	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62
Heat Value		Btu/lb	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Saturation Factor	S		0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Height of Vapor Space	h_v	ft	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00	4.00
Volume of Vapor Space	V_V	ft^3	45,228	45,228	45,228	45,228	45,228	45,228	66,035	66,035	66,035	66,035	66,035	49,075	49,075	49,075	49,075	49,075	49,075	49,075	49,075
Paint Color			White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White
Tank Condition			Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good
Tank Solar Absorptance Factor	α		0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Daily Vapor Temp. Range	ΔT	deg R	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78
Heated Product Temperature			120.00	120.00	120.00	120.00	120.00	120.00	ambient	ambient	ambient	ambient	ambient	120.00	120.00	120.00	120.00	120.00	120.00	120.00	120.00
Liquid Bulk Temp.	T_B	deg R	579.60	579.60	579.60	579.60	579.60	579.60	543.67	543.67	543.67	543.67	543.67	579.60	579.60	579.60	579.60	579.60	579.60	579.60	579.60
Daily Average Liquid Surface Temp.	T_{LA}	deg R	579.60	579.60	579.60	579.60	579.60	579.60	546.33	546.33	546.33	546.33	546.33	579.60	579.60	579.60	579.60	579.60	579.60	579.60	579.60
Vapor Pressure Method			RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP
RVP			11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Slope of ASTM Distillation Curve			3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Vapor Pressure Function Constant	A		11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69
Vapor Pressure Function Constant	B		5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91
True Vapor Pressure of Liquid	P	psia	11.00	11.00	11.00	11.00	11.00	11.00	9.37	9.37	9.37	9.37	9.37	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
Tank Landing Emissions																					
Standing Idle Controlled?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Heat Input From Vapor		MMBtu/event	9.43	9.43	9.43	9.43	9.43	9.43	13.77	13.77	13.77	13.77	13.77	10.24	10.24	10.24	10.24	10.24	10.24	10.24	10.24
Standing Idle Volume		ft^3/event	45,228	45,228	45,228	45,228	45,228	45,228	66,035	66,035	66,035	66,035	66,035	49,075	49,075	49,075	49,075	49,075	49,075	49,075	49,075
CO2 Emissions		tons/event	7.75E-01	7.75E-01	7.75E-01	7.75E-01	7.75E-01	7.75E-01	1.13E+00	1.13E+00	1.13E+00	1.13E+00	1.13E+00	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01
CH4 Emissions		tons/event	3.12E-05	3.12E-05	3.12E-05	3.12E-05	3.12E-05	3.12E-05	4.55E-05	4.55E-05	4.55E-05	4.55E-05	4.55E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05
N2O Emissions		tons/event	6.24E-06	6.24E-06	6.24E-06	6.24E-06	6.24E-06	6.24E-06	9.11E-06	9.11E-06	9.11E-06	9.11E-06	9.11E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06
Refilling Losses																					
Refill Controlled?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Pump Rate		gal/hr	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000
Vapor Space Expansion Factor	K_E		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Standing Idle Saturation Factor	K_s		0.30	0.30	0.30	0.30	0.30	0.30	0.33	0.33	0.33	0.33	0.33	0.30	0.30	0.30	0.30	0.30	0.30	0.30	0.30
Vapor Pressure Function	P*		3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	2.48E-01	2.48E-01	2.48E-01	2.48E-01	2.48E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01
Saturation Correction Factor	C_{sf}		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Filling Losses	L_{FL}	lb	757.09	757.09	757.09	757.09	757.09	757.09	998.76	998.76	998.76	998.76	998.76	821.50	821.50	821.50	821.50	821.50	821.50	821.50	821.50
Heat Input From Vapor		MMBtu/event	15.14	15.14	15.14	15.14	15.14	15.14	19.98	19.98	19.98	19.98	19.98	16.43	16.43	16.43	16.43	16.43	16.43	16.43	16.43
Total Refilling Volume		ft^3/event	45,228	45,228	45,228	45,228	45,228	45,228	66,035	66,035	66,035	66,035	66,035	49,075	49,075	49,075	49,075	49,075	49,075	49,075	49,075
CO2 Emissions		tons/event	1.24E+00	1.24E+00	1.24E+00	1.24E+00	1.24E+00	1.24E+00	1.64E+00	1.64E+00	1.64E+00	1.64E+00	1.64E+00	1.35E+00	1.35E+00	1.35E+00	1.35E+00	1.35E+00	1.35E+00	1.35E+00	1.35E+00
CH4 Emissions		tons/event	5.01E-05	5.01E-05	5.01E-05	5.01E-05	5.01E-05	5.01E-05	6.61E-05	6.61E-05	6.61E-05	6.61E-05	6.61E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05
N2O Emissions		tons/event	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.00E-05	1.32E-05	1.32E-05	1.32E-05	1.32E-05	1.32E-05	1.09E-05	1.09E-05	1.09E-05	1.09E-05	1.09E-05	1.09E-05	1.09E-05	1.09E-05
Total Emissions																					
		Tank EPN	**T120**	**T121**	**T122**	**T123**	**T124**	**T125**	**T135**	**T136**	**T137**	**T138**	**T139**	**T154**	**T155**	**T156**	**T157**	**T158**	**T159**	**T160**	**T161**
CO2 Emission Rate		tons/event	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.77E+00	2.77E+00	2.77E+00	2.77E+00	2.77E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00
CH4 Emission Rate		tons/event	8.13E-05	8.13E-05	8.13E-05	8.13E-05	8.13E-05	8.13E-05	1.12E-04	1.12E-04	1.12E-04	1.12E-04	1.12E-04	8.82E-05	8.82E-05	8.82E-05	8.82E-05	8.82E-05	8.82E-05	8.82E-05	8.82E-05
N2O Emission Rate		tons/event	1.63E-05	1.63E-05	1.63E-05	1.63E-05	1.63E-05	1.63E-05	2.23E-05	2.23E-05	2.23E-05	2.23E-05	2.23E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05	1.76E-05

Notes

1. Codes for tank heel status: Full Heel (FULL), Partial Heel (PARTIAL), and Drain Dry (DRAIN).
2. Seal loss factors and seal-related wind speed component from AP-42, Table 7.1-8. Wind speed from AP-42, Table 7.1-9.
3. Tank temperatures will be controlled so that the true vapor pressure will not exceed 11 psia for any material stored in a floating roof tank.

Green House Gas Emission Factors				
40 CFR 98 Name	**Material Name**	**kg CO2/MMBtu**	**kg CH4/mmBtu**	**kg N2O/mmBtu**
Crude Oil	Condensate	74.54	0.003	0.0006

Equations Used:

Standing Idle - Drain Dry (Eqn 2-22)

Losses = $0.0063\ W_l\ (\pi\ D^2 / 4)$

Filling - IFR with Heel & Drain Dry / Clean Tanks (Eqn 2-26)

Losses = $(P\ V_V / R\ T)\ M_V\ S\ (1 - DRE)$

Events per hour: 1 tank per hour
Events per year: 3 landings per tank

Total Annual Emissions (tpy)		GWP	CO2e (tpy)
CO2	1.31E+02	1	130.53
CH4	5.25E-03	25	0.13
N2O	1.05E-03	298	0.31
			130.66

Table A-8b
Storage Tank Emission Calculations - High Leg Landings, High Vapor Pressure Material (includes both routine and MSS landings)
Magellan Corpus Christi Splitter Project
August 2014

Constants			
Atmospheric Pressure	Pa	psia	14.70
Control Device			VCU
Control Device Efficiency	CE		99%
Degassing Turnovers			4
Degassing Air Flow Rate		cfm	300
Degassing Saturation Factor			0.5

		Tank EPN	T120	T121	T122	T123	T124	T125	T135	T136	T137	T138	T139	T154	T155	T156	T157	T158	T159	T160	T161
Type			IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR
Diameter	D	ft	120	120	120	120	120	120	145	145	145	145	145	125	125	125	125	125	125	125	125
Landed Roof Leg Height		ft	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5	6.5
Month of Landing Event			July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July	July
Max Daily Ambient Temperature	T_{MAX}	deg F	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30	93.30
Min Daily Ambient Temperature	T_{MIN}	deg F	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80	74.80
Daily Total Solar Insulation Factor	I	Btu/(ft2*day)	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38	1987.38
Daily Average Ambient Temperature	T_{AA}	deg R	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65	543.65
Average ambient wind speed	v	mph	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6	11.6
Days Off-Float (before degas/clean)	n_d	day	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Tank Heel Status [1]			Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain	Drain
Height of Liquid Heel	h_{le}	ft	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001
Product Stored			Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate	Condensate
Vapor Molecular Wt.	M_V	lb/lbmole	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1	63.1
Liquid Molecular Wt.	M_L	lb/lbmole	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9	173.9
Liquid Density	W_l	lb/gal	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62	6.62
Heat Value		Btu/lb	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000	20,000
Saturation Factor	S		0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Height of Vapor Space	h_v	ft	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50	6.50
Volume of Vapor Space	V_V	ft^3	73,502	73,502	73,502	73,502	73,502	73,502	107,318	107,318	107,318	107,318	107,318	79,755	79,755	79,755	79,755	79,755	79,755	79,755	79,755
Paint Color			White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White	White
Tank Condition			Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good	Good
Tank Solar Absorptance Factor	α		0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17	0.17
Daily Vapor Temp. Range	ΔT	deg R	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78	22.78
Heated Product Temperature			120	120	120	120	120	120	ambient	ambient	ambient	ambient	ambient	120	120	120	120	120	120	120	120
Liquid Bulk Temp.	T_B	deg R	579.60	579.60	579.60	579.60	579.60	579.60	543.67	543.67	543.67	543.67	543.67	579.60	579.60	579.60	579.60	579.60	579.60	579.60	579.60
Daily Average Liquid Surface Temp.	T_{LA}	deg R	579.60	579.60	579.60	579.60	579.60	579.60	546.33	546.33	546.33	546.33	546.33	579.60	579.60	579.60	579.60	579.60	579.60	579.60	579.60
Vapor Pressure Method			RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP	RVP
RVP			11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11	11
Slope of ASTM Distillation Curve			3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Vapor Pressure Function Constant	A		11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69	11.69
Vapor Pressure Function Constant	B		5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91	5166.91
True Vapor Pressure of Liquid	P	psia	11.00	11.00	11.00	11.00	11.00	11.00	9.37	9.37	9.37	9.37	9.37	11.00	11.00	11.00	11.00	11.00	11.00	11.00	11.00
Tank Landing Emissions																					
Standing Idle Losses																					
Standing Idle Controlled?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Standing Idle Losses	L_{SL}	lb/event	471.67	471.67	471.67	471.67	471.67	471.67	688.68	688.68	688.68	688.68	688.68	511.80	511.80	511.80	511.80	511.80	511.80	511.80	511.80
Heat Input From Vapor		MMBtu/event	9.43	9.43	9.43	9.43	9.43	9.43	13.77	13.77	13.77	13.77	13.77	10.24	10.24	10.24	10.24	10.24	10.24	10.24	10.24
Standing Idle Volume		ft^3/event	73,502	73,502	73,502	73,502	73,502	73,502	107,318	107,318	107,318	107,318	107,318	79,755	79,755	79,755	79,755	79,755	79,755	79,755	79,755
CO2 Emissions		tons/event	7.75E-01	7.75E-01	7.75E-01	7.75E-01	7.75E-01	7.75E-01	1.13E+00	1.13E+00	1.13E+00	1.13E+00	1.13E+00	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01	8.41E-01
CH4 Emissions		tons/event	3.12E-05	3.12E-05	3.12E-05	3.12E-05	3.12E-05	3.12E-05	4.55E-05	4.55E-05	4.55E-05	4.55E-05	4.55E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05	3.38E-05
N2O Emissions		tons/event	6.24E-06	6.24E-06	6.24E-06	6.24E-06	6.24E-06	6.24E-06	9.11E-06	9.11E-06	9.11E-06	9.11E-06	9.11E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06	6.77E-06
Degassing Losses																					
Tank Degassed?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Degassing Controlled?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Moles		lbmole	65.00	65.00	65.00	65.00	65.00	65.00	85.75	85.75	85.75	85.75	85.75	70.53	70.53	70.53	70.53	70.53	70.53	70.53	70.53
VOC Mass Vapor	Q	lb/event	4101.69	4101.69	4101.69	4101.69	4101.69	4101.69	5410.99	5410.99	5410.99	5410.99	5410.99	4450.62	4450.62	4450.62	4450.62	4450.62	4450.62	4450.62	4450.62
Controlled Degas VOC Emissions	E_P	lb/event	41.02	41.02	41.02	41.02	41.02	41.02	54.11	54.11	54.11	54.11	54.11	44.51	44.51	44.51	44.51	44.51	44.51	44.51	44.51
Heat Input From Vapor		MMBtu/event	82.03	82.03	82.03	82.03	82.03	82.03	108.22	108.22	108.22	108.22	108.22	89.01	89.01	89.01	89.01	89.01	89.01	89.01	89.01
Total Degassing Volume		ft^3/event	294,008	294,008	294,008	294,008	294,008	294,008	429,272	429,272	429,272	429,272	429,272	319,019	319,019	319,019	319,019	319,019	319,019	319,019	319,019
Degassing Duration		hr	16.33	16.33	16.33	16.33	16.33	16.33	23.85	23.85	23.85	23.85	23.85	17.72	17.72	17.72	17.72	17.72	17.72	17.72	17.72
CO2 Emissions		tons/event	6.74E+00	6.74E+00	6.74E+00	6.74E+00	6.74E+00	6.74E+00	8.89E+00	8.89E+00	8.89E+00	8.89E+00	8.89E+00	7.31E+00	7.31E+00	7.31E+00	7.31E+00	7.31E+00	7.31E+00	7.31E+00	7.31E+00
CH4 Emissions		tons/event	2.71E-04	2.71E-04	2.71E-04	2.71E-04	2.71E-04	2.71E-04	3.58E-04	3.58E-04	3.58E-04	3.58E-04	3.58E-04	2.94E-04	2.94E-04	2.94E-04	2.94E-04	2.94E-04	2.94E-04	2.94E-04	2.94E-04
N2O Emissions		tons/event	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	5.43E-05	7.16E-05	7.16E-05	7.16E-05	7.16E-05	7.16E-05	5.89E-05	5.89E-05	5.89E-05	5.89E-05	5.89E-05	5.89E-05	5.89E-05	5.89E-05
Refilling Losses																					
Refill Controlled?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Pump Rate		gal/hr	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000	840,000
Vapor Space Expansion Factor	K_E		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Standing Idle Saturation Factor	K_s		0.21	0.21	0.21	0.21	0.21	0.21	0.24	0.24	0.24	0.24	0.24	0.21	0.21	0.21	0.21	0.21	0.21	0.21	0.21
Vapor Pressure Function	P*		3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	2.48E-01	2.48E-01	2.48E-01	2.48E-01	2.48E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01	3.32E-01
Saturation Correction Factor	C_{sf}		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Filling Losses	L_{FL}	lb	1,230.39	1,230.39	1,230.39	1,230.39	1,230.39	1,230.39	1,623.15	1,623.15	1,623.15	1,623.15	1,623.15	1,335.06	1,335.06	1,335.06	1,335.06	1,335.06	1,335.06	1,335.06	1,335.06
Heat Input From Vapor		MMBtu/event	24.61	24.61	24.61	24.61	24.61	24.61	32.46	32.46	32.46	32.46	32.46	26.70	26.70	26.70	26.70	26.70	26.70	26.70	26.70
Total Refilling Volume		ft^3/event	73,502	73,502	73,502	73,502	73,502	73,502	107,318	107,318	107,318	107,318	107,318	79,755	79,755	79,755	79,755	79,755	79,755	79,755	79,755
CO2 Emissions		tons/event	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.02E+00	2.67E+00	2.67E+00	2.67E+00	2.67E+00	2.67E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00	2.19E+00
CH4 Emissions		tons/event	8.14E-05	8.14E-05	8.14E-05	8.14E-05	8.14E-05	8.14E-05	1.07E-04	1.07E-04	1.07E-04	1.07E-04	1.07E-04	8.83E-05	8.83E-05	8.83E-05	8.83E-05	8.83E-05	8.83E-05	8.83E-05	8.83E-05
N2O Emissions		tons/event	1.63E-05	1.63E-05	1.63E-05	1.63E-05	1.63E-05	1.63E-05	2.15E-05	2.15E-05	2.15E-05	2.15E-05	2.15E-05	1.77E-05	1.77E-05	1.77E-05	1.77E-05	1.77E-05	1.77E-05	1.77E-05	1.77E-05
Total Emissions																					
		Tank EPN	**T120**	**T121**	**T122**	**T123**	**T124**	**T125**	**T135**	**T136**	**T137**	**T138**	**T139**	**T154**	**T155**	**T156**	**T157**	**T158**	**T159**	**T160**	**T161**
CO2 Emission Rate		tons/event	9.54E+00	9.54E+00	9.54E+00	9.54E+00	9.54E+00	9.54E+00	1.27E+01	1.27E+01	1.27E+01	1.27E+01	1.27E+01	1.03E+01	1.03E+01	1.03E+01	1.03E+01	1.03E+01	1.03E+01	1.03E+01	1.03E+01
CH4 Emission Rate		tons/event	3.84E-04	3.84E-04	3.84E-04	3.84E-04	3.84E-04	3.84E-04	5.11E-04	5.11E-04	5.11E-04	5.11E-04	5.11E-04	4.17E-04	4.17E-04	4.17E-04	4.17E-04	4.17E-04	4.17E-04	4.17E-04	4.17E-04
N2O Emission Rate		tons/event	7.68E-05	7.68E-05	7.68E-05	7.68E-05	7.68E-05	7.68E-05	1.02E-04	1.02E-04	1.02E-04	1.02E-04	1.02E-04	8.33E-05	8.33E-05	8.33E-05	8.33E-05	8.33E-05	8.33E-05	8.33E-05	8.33E-05

Notes

1. Codes for tank heel status: Full Heel (FULL), Partial Heel (PARTIAL), and Drain Dry (DRAIN).
2. Seal loss factors and seal-related wind speed component from AP-42, Table 7.1-8.
Wind speed from AP-42, Table 7.1-9.
3. Tank temperatures will be controlled so that the true vapor pressure will not exceed 11 psia for any material stored in a floating roof tank.

Equations Used:

Standing Idle - Drain Dry (Eqn 2-22

Losses = $0.0063\ W_l\ (\pi\ D^2 / 4)$

Filling - IFR with Heel & Drain Dry / Clean Tanks (Eqn 2-26)

Losses = $(P\ V_V / R\ T)\ M_V\ S\ (1 - DRE)$

Tank Degassing

Losses = $(P\ V / R\ T)\ D_e\ M_V\ (1 - DRE)$

Post-Control Degassing

This is only addressed for materials VP > 0.5. Emissions based on maximum allowed 34,000 ppm concentration vented.

Losses = $34{,}000/1{,}000{,}000 \times V_V$ / 379 scf/lb-mol x 16 lb/lb-mol methane

Events per hou 1 tank per hour
Events per year 1 landings per tank

Emission Summary	lb/hr	tpy
VOC	#DIV/0!	1.78
NOx	#DIV/0!	#DIV/0!
CO	#DIV/0!	#DIV/0!
H_2S	0.22	0.003
SO_2	4.42	0.20

Green House Gas Emission Factors				
40 CFR 98 Name	**Material Name**	**kg CO2/MMBtu**	**kg CH4/mmBtu**	**kg N2O/mmBtu**
Crude Oil	Condensate	74.54	0.003	0.0006

Total Annual Emissions (tpy)		GWP	CO2e (tpy)
CO2	203.47	1	203.47
CH4	0.01	25	0.20
N2O	0.002	298	0.49
			204.16

Table A-9
Pressure Tank MSS
Magellan Corpus Christi Splitter Project
August 2014

Basis:
- All liquid is drained from the tank prior to opening

	LPG	Propane	Butane
Vessel Volume (bbl):	17,500	2,000	2,000
Events per year:	1	2	2
Temperature (F):	81.03	81.03	81.03
Storage Pressure (psia):	34	150	53
Molecular Weight:	57.9	44.1	58.4

Displaced LPG Vapors to VCU:

Ideal Gas Law: pV = nRT
ft3/lb-mol = (10.731 ft3·psia/R·lb-mol * 540.7 R) / 34 psia
ft3/lb-mol = 170.66

Annual Emissions:
$$\frac{98{,}255\ ft^3}{event} \times \frac{1\ event}{yr} \times \frac{1\ lb\text{-}mol}{170.66\ ft^3} \times \frac{57.9\ lb}{lb\text{-}mol} \times \frac{1\ ton}{2000\ lb} = 16.67\ \frac{ton}{yr}$$

Displaced Butane Vapors to VCU:

Ideal Gas Law: pV = nRT
ft3/lb-mol = (10.731 ft3·psia/R·lb-mol * 540.7 R) / 53 psia
ft3/lb-mol = 109.48

Annual Emissions:
$$\frac{11{,}229\ ft^3}{event} \times \frac{2\ event}{yr} \times \frac{1\ lb\text{-}mol}{109.48\ ft^3} \times \frac{58.4\ lb}{lb\text{-}mol} \times \frac{1\ ton}{2000\ lb} = 5.99\ \frac{ton}{yr}$$

Displaced Propane Vapors to VCU:

Ideal Gas Law: pV = nRT
ft3/lb-mol = (10.731 ft3·psia/R·lb-mol * 540.7 R) / 150 psia
ft3/lb-mol = 38.68

Annual Emissions:
$$\frac{11{,}229\ ft^3}{event} \times \frac{2\ event}{yr} \times \frac{1\ lb\text{-}mol}{38.68\ ft^3} \times \frac{44.1\ lb}{lb\text{-}mol} \times \frac{1\ ton}{2000\ lb} = 12.80\ \frac{ton}{yr}$$

Control Device Emissions:

HC Destruction Efficiency:	99%		
Heat content of vapors:	21,561	btu/lb	LPG
	21,300	btu/lb	Butane
	21,653	btu/lb	Propane

Combusted Material	Pollutant	Emissions Factor[1] (Value)	Emissions Factor[1] (Units)	Controlled Vapors MMBtu/yr	Emissions (ton/yr)	GWP[2]	CO_2e (ton/yr)
LPG	CO_2	61.71	kg/MMBtu	718.76	48.89	1	**48.89**
	CH_4	0.003	kg/MMBtu		0.002	25	**0.06**
	N_2O	0.0006	kg/MMBtu		0.0005	298	**0.14**
Butane	CO_2	64.77	kg/MMBtu	255.18	18.22	1	18.22
	CH_4	0.003	kg/MMBtu		0.001	25	0.02
	N_2O	0.0006	kg/MMBtu		0.0002	298	0.05
Propane	CO_2	62.87	kg/MMBtu	554.40	38.42	1	38.42
	CH_4	0.003	kg/MMBtu		0.002	25	0.05
	N_2O	0.0006	kg/MMBtu		0.0004	298	0.11

Proposed GHG Emission Limits (bold font) based on maximum scenario.

Notes:
1. Emission factors from 40 CFR 98, Tables C-1 and C-2.
2. Global warming potential factors from 40 CFR 98, Table A-1.

Table A-10
MSS Vapor Combustion Unit Pilot/Assist Gas Combustion
Magellan Corpus Christi Splitter Project
August 2014

Basis:

Hourly natural gas usage (scf/hr): 24,000
Annual natural gas usage (scf/hr): 6,000
Natural gas heating value (btu/scf): 1,050

Combusted Material	Pollutant	Emissions Factor[1]		Emissions	GWP[2]	CO_2e
		(Value)	(Units)	(ton/yr)		(ton/yr)
Natural Gas	CO_2	53.06	kg/MMBtu	3,227.87	1	3227.87
	CH_4	0.001	kg/MMBtu	0.06	25	1.52
	N_2O	0.0001	kg/MMBtu	0.01	298	1.81

Notes:

1. Emission factors from 40 CFR 98, Tables C-1 and C-2.
2. Global warming potential factors from 40 CFR 98, Table A-1.
3. Natural Gas (MMBtu/yr) = pilot gas flow rate (scf/hr) x 1,050 But/scf x 1 MMBtu/10^6 Btu x 8,760 hr/yr

Table A-11
Vessels & Piping Maintenance, Startup, and Shutdown Activity Emissions
Magellan Corpus Christi Splitter Project
August 2014

Basis:
- The volumes and frequencies listed below are for emission estimation purposes only. The actual activity type, frequency, volume, etc. may vary so long as the estimated emissions are not exceeded.

Equipment Type	Units	Pumps	Filters, Meters, Valves, Strainers	Vessels, Piping, and Splitter Column
Annual Events	events/yr	30	500	60
Typical Event Duration	hrs	1	1	1
Molecular Weight of Vapor	lb/lb-mole	63.1	63.1	63.1
Liquid Density	lb/gal	6.62	6.62	6.62
Temperature	°R	554.60	554.60	554.60
Liquid Vapor Pressure	psia	11.00	11.00	11.00
Volume	ft^3/event	200.00	50.00	24,500.00
Equipment Inner Surface Area	ft^2	465.13	174.69	6,534.51
Equipment MSS - Vapors Vented Prior to Opening				
Vented to Control	Yes/No	No	No	Yes
Moles	M_v/event	0.370	0.092	45.288
Total Venting VOC Emissions	tpy	0.35	1.46	1.71
Equipment MSS - Refilling				
Vented to Control	Yes/No	No	No	Yes
Refilling Loss Factor	lb/Mgal loaded	9.36	9.36	9.36
Refilling Loss Per Event	lbs/event	14.00	3.50	1714.66
Refilling Loss	tpy	0.21	0.87	1.03

* 2.5% of piping volume, 20% other vessel volume

Ideal Gas Law (vapors vented prior to opening)
pV = nRT

Liquid Refilling
L = 12.46 * S * P * M / T

where:
L = Loading Losses, lb/1000 gallons
S = Saturation Factor, see Table 5.2-1 in AP-42, Section 5.2.
P = True vapor pressure, psia
M = Molecular weight of vapors, lb/lb-mol
T = Temperature of bulk liquid loaded, R (F + 460)
R = Ideal gas constant
V = Volume of Vapor Space

Control Device Emissions:
Control Device: FL-1
VOC Destruction Efficiency: 98%
Heat content of vapors: 20,000 Btu/lb

Combusted Material	Pollutant	Emissions Factor[1]		Controlled Vapors	Emissions	GWP[2]	CO_2e
		(Value)	(Units)	MMBtu/yr	(ton/yr)		(ton/yr)
Condensate/Crude	CO_2	74.54	kg/MMBtu	5486.77	450.83	1	450.83
	CH_4	0.003	kg/MMBtu		0.02	25	0.45
	N_2O	0.0006	kg/MMBtu		0.004	298	1.08

Notes:
1. Emission factors from 40 CFR 98, Tables C-1 and C-2.
2. Global warming potential factors from 40 CFR 98, Table A-1.

Table A-12
Wastewater Treatment Emissions (from MSS-VCU)
Magellan Corpus Christi Splitter Project
August 2014

Basis:

- The desalter exit streams consist of desalted crude oil and effluent water which contains salt.
- The effluent water will contain 250-500 ppm oil, excluding unplanned upsets.
- The crude oil desalter will require inlet water to consist of 4% - 6% of the inlet oil flow rate; 5% used for calculations.
- 6000 gal/hr wash water stream
- Assume Oil emissions are as methane for GHG calculation purposes

Desalter Inlet water needs:	5.00%	of condensate flow
Wash water(gal/hr):	6,000	
Oil concentration (ppmv):	500	
Portion of oil to vapor:	20%	
Density of oil (lb/gal):	6.19	

$$\text{Desalter Inlet water needs} = \frac{100{,}000\ \text{bbl condensate}}{\text{day}} \times \frac{42\ \text{gal}}{\text{bbl}} \times 5\%\ \text{water} \times \frac{\text{day}}{24\ \text{hr}} = 8{,}750\ \frac{\text{gal water}}{\text{hr}}$$

$$\text{Total Water Flow} = \frac{6{,}000\ \text{gal wash water}}{\text{hr}} + \frac{8{,}750\ \text{gal desalter water}}{\text{hr}} = 14{,}750\ \frac{\text{gal water}}{\text{hr}}$$

$$\text{Oil Flow} = \frac{14{,}750\ \text{gal water}}{\text{hr}} \times \frac{500\ \text{parts oil}}{1{,}000{,}000\ \text{parts}} \times \frac{6.19\ \text{lb oil}}{\text{gal}} = 45.65\ \frac{\text{lb oil}}{\text{hr}}$$

$$\text{Oil Emissions} = \frac{45.65\ \text{lb oil}}{\text{hr}} \times 20\%\ \text{oil lost} = 9.13\ \frac{\text{lb}}{\text{hr}}$$

$$\text{Oil Emissions} = \frac{9.13\ \text{lb}}{\text{hr}} \times \frac{8760\ \text{hr}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = 39.99\ \frac{\text{ton}}{\text{yr}}\ \text{as } CH_4$$

Control Device Emissions:

Assume all oil vapors as CH_4 converted to CO_2 in VCU : CO_2 - CH_4 x 44 lb/mole / 16 lb/mole

Pollutant	Uncontrolled Vapors (as CH4)	CO2 Emissions	
	tpy	tpy	CO2e tpy
CO2	39.99	109.96	109.96

Appendix B

RBLC Search Results

Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide Equivalent (CO2e) And Process Contains 'heater'
Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide Equivalent (CO2e) And Process Contains 'boiler'

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY DESCRIPTION	PERMIT NOTES	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
*CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	Note: Final PSD permit issued on 11/18/2011. Permit appealed t EAB, and EAB denied review of this appeal on 9/17/2012. Petitioner filed a petition for review with the Ninth Circuit Court of Appeals. Court has not yet issued a decision.	AUXILIARY BOILER	12.31	NATURAL GAS	110	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	P	ANNUAL BOILER TUNE-UPS	0			BACT-PSD	
*CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	Note: Final PSD permit issued on 11/18/2011. Permit appealed t EAB, and EAB denied review of this appeal on 9/17/2012. Petitioner filed a petition for review with the Ninth Circuit Court of Appeals. Court has not yet issued a decision.	AUXILIARY HEATER	19.6	NATURAL GAS	40	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	N	ANNUAL BOILER TUNEUPS	0				NO EMISSION LIMITS
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturin		Auxiliary Boile	11.31	natural gas	472.4	MMBTU/H		Carbon Dioxide Equivalent (CO2e	P	good combustion practices	51748	TONS/YR	ROLLING 12 MONTH TOTAL	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturin		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Carbon Dioxide Equivalent (CO2e	P	good combustion practices	638	TONS/YR	ROLLING 12 MONTH TOTAL	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Carbon Dioxide Equivalent (CO2e)	P	good operating practices & use of natural gas	345	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Carbon Dioxide Equivalent (CO2e)	P	proper operation and use of natural gas	234168	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	BACT-PSD	
*IN-0167	MAGNETATION LLC	MAGNETATION LLC	IRON ORE CONCENTRATE PELLETIZING PLANT		SPACE HEATERS	19.6	NATURAL GAS	1	MMBTU/H EACH	SEVEN (7) NATRUAL GAS FIRED SPACE HEATERS ARE IDENTIFIED AS EU021	Carbon Dioxide Equivalent (CO2e)	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	3587	T/YR	12-MONTH PERIOD	BACT-PSD	
*IN-0167	MAGNETATION LLC	MAGNETATION LLC	IRON ORE CONCENTRATE PELLETIZING PLANT		COKE BREEZE ADDITIVE SYSTEM AIR HEATER	19.6	NATURAL GAS	1.7	MMBTU/H	COKE BREEZE ADDITIVE SYSTEM IS IDENTIFIED AS EU009.	Carbon Dioxide Equivalent (CO2e)	P	USE OG NATURAL GAS AND GOOD COMBUSTION PRACTICES	871	T/YR	12-MONTH ROLLING TOTAL	BACT-PSD	
*IN-0167	MAGNETATION LLC	MAGNETATION LLC	IRON ORE CONCENTRATE PELLETIZING PLANT		GROUND LIMESTONE/DOLOMITE ADDITIVE SYSTEM AIR HEATER	19.6	NATURAL GAS	19	MMBTU/H	IDENTIFIED AS EU010, USES BAGHOUSE CE010 EXHAUSTING TO STACK SV010	Carbon Dioxide Equivalent (CO2e)	P	USE OF NATURAL GAS AND GOOD COMBUSTION PRACTICES	9737	T/YR	12-MONTH ROLLING TOTAL	BACT-PSD	
*LA-0271	PLAQUEMINE NGL FRACTIONATION PLANT	CROSSTEX PROCESSING SERVICES, LLC	Facility fractionates inlet natural gas liquids into constituent product streams for sale.		Heat Medium Oil (HMO) Heaters (HMO-01 & HMO-02)	12.31	Natural gas	177	MM Btu/hr	Natural gas: 175 MM Btu/hr Process gas: 2 MM Btu/hr	Carbon Dioxide Equivalent (CO2e)	P	Improved combustion measures: heater tuning, optimization, and installation of instrumentation and controls; insulation installed according to the heater manufacturer?s specifications; operational monitoring as well as proper maintenance in order to minimize air infiltration.	0			BACT-PSD	
*LA-0271	PLAQUEMINE NGL FRACTIONATION PLANT	CROSSTEX PROCESSING SERVICES, LLC	Facility fractionates inlet natural gas liquids into constituent product streams for sale.		Mol Sieve Dehy Regen Heater (H-01)	13.31	Natural gas	30	MM Btu/hr		Carbon Dioxide Equivalent (CO2e)	P	Improved combustion measures: heater tuning, optimization, and installation of instrumentation and controls; insulation installed according to the heater manufacturer?s specifications; operational monitoring as well as proper maintenance in order to minimize air infiltration.	0			BACT-PSD	
*MI-0404	GERDAU MACSTEEL, INC.	GERDAU MACSTEEL, INC.	Steel Mill	The facility is a steel ‘‘mini-mill‘‘. Gerdau melts steel to produce steel at varying specificatioins to meet customer demands. Steel is melted in an electric arc furnac and processed in the plant. FACILITY-WIDE POLLUTANTS in addition to those below: PM10 +32.4 PM2.5 +33.6 Lead +0.28 GHG +169737 H2SO4 +6.68	Slidegate Heater (EUSLIDEGATEHEATER)	81.29	Natural gas	0		Small, natural-gas fired, internally vented process heater that preheats the submerged entry nozzle (SEN) prior to it being inserted into the caster mold. Molten metal is added after the SEN is in place.	Carbon Dioxide Equivalent (CO2e)	N	Energy efficiency practices	0			BACT-PSD	PSD BACT was determined to be energy efficiency practices, an energy efficiency management plan is required. No numeric BACT limit was given.
*OH-0355	GENERAL ELECTRIC AVIATION, EVENDALE PLANT	GENERAL ELECTRIC	Manufacturer of Aircraft engines	Installing 2 new production test cells for engines and turbines fueled by liquid and gaseous fuels and 4 associated air preheaters	4 Indirect-Fired Air Preheaters	13.31	Natural gas	0		Four preheaters for 2 production test cells for aviation engines and turbines	Carbon Dioxide Equivalent (CO2e)	N		74000	T/YR	TOTAL FOR 2 TEST CELLS AND 4 PREHEATERS	N/A	T/YR limit is in rolling 12-months and is total for both test cells and their 4 preheaters. Must develop an Emissions Protocol Document on the potential to emit.
*OH-0357	BP-HUSKY REFINING LLC	BP PRODUCTS, NORTH AMERICA INC.	Refinery Processing of Crude Oils into Petroleum Products.	Toledo Feedstock Optimization Project. Replacing heaters i Crude Vacuum 1 process unit and replace Vacuum Tower; upgrading metallurgy in Crude Tower; reducing coke drum cycle time in Coker 3; modification to Coker Gas Plant to improve light ends recovery; new benzene stripper for Wastewater treatment; new amine stripper to improve fuel gas treatment. PSD for GHGs only.	Refinery Process Heater / Vacuum Furnace	50.003	Refinery fuel gas	150	MMBtu/H	Process heater fired with any combination of refinery fuel gas, natural gas, or liquid petroleum gas. Because they are designed to burn gas 1 subcategory fuels, only work practice standards from Table 3 of Part 63 Subpart DDDDD apply. Using continuous oxygen trim system to maintain optimum air to fuel ratio, with tune up every 5 years.	Carbon Dioxide Equivalent (CO2e)	N		82375	T/YR	PER ROLLING 12-MONTHS	BACT-PSD	
*OH-0357	BP-HUSKY REFINING LLC	BP PRODUCTS, NORTH AMERICA INC.	Refinery Processing of Crude Oils into Petroleum Products.	Toledo Feedstock Optimization Project. Replacing heaters in Crude Vacuum 1 process unit and replace Vacuum Tower; upgrading metallurgy in Crude Tower; reducing coke drum cycle time in Coker 3; modification to Coker Gas Plant to improve light ends recovery; new benzene stripper for Wastewater treatment; new amine stripper to improve fuel gas treatment. PSD for GHGs only.	Refinery Process Heaters / Crude furnaces (2)	50.003	Refinery fuel gas	225	MMBtu/H	Two furnaces/refinery process heaters fired with any combination of refinery fuel gas, natural gas, or liquid petroleum gas. Because they are designed to burn gas 1 subcategory fuels, only work practice standards from Table 3 of Part 63 Subpart DDDDD apply. Using continuous oxygen trim system to maintain optimum air to fuel ratio, with tune up every 5 years.	Carbon Dioxide Equivalent (CO2e)	N		123562	T/YR	PER ROLLING 12-MONTHS, EACH UNIT	BACT-PSD	Emission factor derived from actual refinery fuel gas data pursuant to 40 CFR Part 98, from 2010 through June of 2012.
*LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMPLETE APPLICATION DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD-LA-768(M-1), ISSUED OCTOBER 14, 2013, CORRECTED THE CAPACITY OF THE AMDEA TANK (2009-F), REVISED THE EMISSION LIMITATIONS FOR THE AMMONIA STORAGE FLARE (2202-B), AND ADDED STARTUP EMISSIONS ATTRIBUTED TO THIS FLARE TO THE PERMIT. THESE CHANGES ARE REFLECTED IN THIS RBLC ENTRY.	PRIMARY REFORMER FURNACE (101-B)	11.39	NATURAL GAS	956.2	MM BTU/HR	NATURAL GAS: 613.5 MM BTU/HR PURIFIER WASTE GAS: 326.1 MM BTU/HR HIGH PRESSURE FLASH GAS: 10.4 MM BTU/HR LP SCRUBBER OVERHEAD: 6.2 MM BTU/HR	Carbon Dioxide Equivalent (CO2e)	P	Energy efficiency measures: process integration and improved combustion measures (i.e., combustion tuning, optimization using parametric testing, installation of advanced digital instrumentation).	490025	TPY	ANNUAL MAXIMUM	BACT-PSD	
*CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	Note: Final PSD permit issued on 11/18/2011. Permit appealed t EAB, and EAB denied review of this appeal on 9/17/2012. Petitioner filed a petition for review with the Ninth Circuit Court of Appeals. Court has not yet issued a decision.	AUXILIARY BOILER	12.31	NATURAL GAS	110	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	P	ANNUAL BOILER TUNE-UPS	0			BACT-PSD	
*CA-1212	PALMDALE HYBRID POWER PROJECT	CITY OF PALMDALE	570 MW NATURAL GAS FIRED COMBINED CYCLE POWER PLANT WITH AN INTEGRATED 50 MW SOLAR THERMAL PLANT	Note: Final PSD permit issued on 11/18/2011. Permit appealed t EAB, and EAB denied review of this appeal on 9/17/2012. Petitioner filed a petition for review with the Ninth Circuit Court of Appeals. Court has not yet issued a decision.	AUXILIARY HEATER	19.6	NATURAL GAS	40	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	N	ANNUAL BOILER TUNEUPS	0				NO EMISSION LIMITS
GA-0147	PYRAMAX CERAMICS, LLC - KING'S M:U FACILITY	PYRAMAX CERAMICS, LLC	THIS FACILITY IS A KAOLIN CLAY PROCESSING (CERAMIC PROPPANT MANUFACTURING) PLANT. THE FACILITY WILL USE SPRAY DRYERS AND CALCINERS TO PROCESS THE CLAY.		BOILERS	19.6	NATURAL GAS	9.8	MMBTU/H	THE FACILITY HAS TWO BOILERS	Carbon Dioxide Equivalent (CO2e)	P	Good Combustion Practices, design, and thermal insulation.	5809	T/12-MO ROLLING AVG		BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturin		Auxiliary Boile	11.31	natural gas	472.4	MMBTU/H		Carbon Dioxide Equivalent (CO2e	P	good combustion practices	51748	TONS/YR	ROLLING 12 MONTH TOTAL	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturin		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Carbon Dioxide Equivalent (CO2e	P	good combustion practices	638	TONS/YR	ROLLING 12 MONTH TOTAL	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Carbon Dioxide Equivalent (CO2e)	P	good operating practices & use of natural gas	345	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Carbon Dioxide Equivalent (CO2e)	P	proper operation and use of natural gas	234168	TONS/YR	ROLLING TWELVE (12) MONTH TOTAL	BACT-PSD	
*IN-0158	ST. JOSEPH ENEGRY CENTER, LLC	ST. JOSEPH ENERGY CENTER, LLC	STATIONARY ELECTRIC UTILITY GENERATING STATION		TWO (2) NATURAL GAS AUXILIARY BOILERS	13.31	NATURAL GAS	80	MMBTU/H	BOTH BOILERS, LABELED AS B001 AND B002, ARE EQUIPPED WITH LOW NOX BURNERS WITH FLUE GAS REGULATION. THIS IS CONSIDERED A STEAM GENERATING UNIT.	Carbon Dioxide Equivalent (CO2e)	P	OPERATION AND MAINTENANCE PRACTICES; COMBUSTION TURNING; OXYGEN TRIM CONTROLS & ANALYZERS; ECONOMIZER; ENERGY EFFICIENT REFRACTORY; CONDENSATE RETURN SYSTEM, INSULATE STEAM AND HOT LINES.	81996	TONS	12 CONSECUTIVE MONTH PERIOD	BACT-PSD	CONTROL METHOD (CONTINUED): MINIMIZATION OF GAS-SIDE HEAT TRANSGER SURFACE DEPOSITS, TURBULATORS FOR FIRETUBE BOILERS STEAM LINE MAINTENANCE, OPERATING AND MAINTENANCE PRACTICES, CONDENSATION RETURN SYSTEM.
*LA-0266	EUNICE GAS EXTRACTION PLANT	CROSSTEX PROCESSING SERVICES, LLC	Natural gas processing plant consisting of two crypgenic process trains.	Complete application date = date of administrative completeness	Boiler B-101-G (12-1) (EQT 0061)	11.31	Natural gas	359	MM Btu/hr		Carbon Dioxide Equivalent (CO2e)	P	Energy efficiency measures: improved combustion measures (e.g. combustion tuning, optimization using parametric testing, advanced digital instrumentation such as temperature sensors, oxygen monitors, CO monitors, and oxygen trim controls); use of an economizer; boiler insulation; and minimization of air infiltration.	0			BACT-PSD	To ensure compliance with CO2e emission limit, heat input (fuel input) to and steam output from the Boiler B-101-G (Emission Point 12-1) shall be monitored continuously. CO2e emissions shall be calculated in accordance with the Mandatory Reporting of Greenhouse Gases Rule (40 CFR 98). The monthly CO2e emission rate, as well as the 12-month rolling averages of CO2e emission rate, shall be calculated and recorded each month.

Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide Equivalent (CO2e) And Process Contains 'heater'
Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide Equivalent (CO2e) And Process Contains 'boiler'

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY DESCRIPTION	PERMIT NOTES	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
*NE-0054	CARGILL, INCORPORATED	CARGILL, INCORPORATED			Boiler K	11.31	natural gas	300	mmbtu/h		Carbon Dioxide Equivalent (CO2e)	P	good combustion practices	153743	TON/YEAR	12-CONSECUTIVE MONTH ROLLING SUM	BACT-PSD	The 178 lbs / 1,000 lbs steam emission limit is only applicable to CO2, not CO2e.
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	799 Megawatt Combined Cycle Combustion Turbine Power Plant	The permit is set up to install either 2 Mitsubishi M501 GAC units or 2 Siemens SGT-8000H units, not both; with dedicated heat recovery steam generators (HRSG), steam turbine generator, and electric generator.	Auxillary Boiler	13.31	Natural Gas	99	MMBtu/H	99 MMBTU/H auxillary boiler with low-NOx burners anc flue gas re-circulation, burning only natural gas. Boiler restricted to 2000 hours of operation per rolling 12-months.	Carbon Dioxide Equivalent (CO2e)	N		11671	T/YR	PER ROLLING 12-MONTHS	BACT-PSD	Restricted to 2000 hours of operation per rolling 12-months.
*OH-0352	OREGON CLEAN ENERGY CENTER	ARCADIS, US, INC.	799 Megawatt Combined Cycle Combustion Turbine Power Plant	The permit is set up to install either 2 Mitsubishi M501 GAC units or 2 Siemens SGT-8000H units, not both; with dedicated heat recovery steam generators (HRSG), steam turbine generator, and electric generator.	2 Combined Cycle Combustion Turbines-Mitsubishi, with duct burners	15.21	Natural Gas	47917	MMSCF/rolling 12-N	Two Mitsubishi 2932 MMBtu/H combined cycle combustion turbines , both with 300 MMBtu/H duct burners, with dry low NOx combustors, SCR, and catalytic oxidizer. Will install either 2 Siemens or 2Mitsubishi, not both (not determined). Short term limits are different with and without duct burners. This process with duct burners.	Carbon Dioxide Equivalent (CO2e)	P	state-of-the-art high efficiency combustion technology	318404	LB/H		BACT-PSD	Additional limit: 840 LB/MW-H gross output. BACT is compliance with the proposed NSPS: 1000 LB CO2/MW-H gross output. 99% of the CO2e is CO2. T/YR limit is for 2 turbines.
*OH-0354	KRATON POLYMERS U.S. LLC	KRATON POLYMERS U.S. LLC	Thermoplastic elastomer manufacturing facility	Two new 249 MMBtu/hour natural gas, distillate oil, and belpre naphtha-fired boilers installed to replace 2 existing coal, distillate oil, and belpre naphtha-fired boilers.	Two 249 MMBtu/H boilers	12.31	Natural Gas	249	MMBtu/H	Two boilers, burning natural gas or distillate oil w/ less than 0.05% sulfur; and co-fired with maximum of 54.8 MMBtu/H Belpre naphtha. Fitted with low-NOx burners with flue gas recirculation, as needed.	Carbon Dioxide Equivalent (CO2e)	N		357522	T/YR		N/A	Netted out for CO2e by replacing old coal/oil-fired boilers.
*PA-0291	HICKORY RUN ENERGY STATION	HICKORY RUN ENERGY LLC	Natural gas-fired combined-cycle electric generation facility that is designed to generate up to 900 MW nominal, using 2 combustion turbine generators and 2 heat recovery steam generators that will provide steam to drive a single steam turbine generator. Each heat recovery steam generator will be equipped with a duct burner which may be utilized at time of peak power demands to supplement power output. The project will also include a natural gasfired auxiliary boiler; a diesel engine-driven emergency generator; a diesel engine-driven firewater pump; a multi-cell evaporative cooling tower; and associated emission control systems, tanks, and other balance of plant equipment.		AUXILIARY BOILER	13.31	Natural Gas	40	MMBTU/HR		Carbon Dioxide Equivalent (CO2e)	N		13696	TPY	12-MONTH ROLLING BASIS	OTHER CASE-BY-CASE	
*LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMPLETE APPLICATION DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD-LA-768(M-1), ISSUED OCTOBER 14, 2013, CORRECTED THE CAPACITY OF THE AMDEA TANK (2009-F), REVISED THE EMISSION LIMITATIONS FOR THE AMMONIA STORAGE FLARE (2202-B), AND ADDED STARTUP EMISSIONS ATTRIBUTED TO THIS FLARE TO THE PERMIT. THESE CHANGES ARE REFLECTED IN THIS RBLC ENTRY.	COMMISSIONING BOILERS 1 & 2 (CB-1 & CB-2)	12.31	NATURAL GAS	217.5	MM BTU/HR	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.	Carbon Dioxide Equivalent (CO2e)	P	Energy efficiency measures: use of economizers and boiler insulation; improved combustion measures (i.e., tuning, optimization, and instrumentation); and minimization of air infiltration.	55986	TPY	ANNUAL MAXIMUM	BACT-PSD	COMMISSIONING BOILERS ARE PERMITTED TO OPERATE FOR 4400 HOURS EACH. Boilers meet the definition of ‘‘temporary boiler‘‘ in 40 CFR 60.41b.
*LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMPLETE APPLICATION DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD-LA-768(M-1), ISSUED OCTOBER 14, 2013, CORRECTED THE CAPACITY OF THE AMDEA TANK (2009-F), REVISED THE EMISSION LIMITATIONS FOR THE AMMONIA STORAGE FLARE (2202-B), AND ADDED STARTUP EMISSIONS ATTRIBUTED TO THIS FLARE TO THE PERMIT. THESE CHANGES ARE REFLECTED IN THIS RBLC ENTRY.	AMMONIA START-UP HEATER (102-B)	13.31	NATURAL GAS	59.4	MM BTU/HR	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.	Carbon Dioxide Equivalent (CO2e)	P	Energy efficiency measures: use of economizers and boiler insulation; improved combustion measures (i.e., tuning, optimization, and instrumentation); and minimization of air infiltration.	1738	TPY	ANNUAL MAXIMUM	BACT-PSD	HEATER IS PERMITTED TO OPERATE 500 HOURS PER YEAR.
*LA-0272	AMMONIA PRODUCTION FACILITY	DYNO NOBEL LOUISIANA AMMONIA, LLC	2780 TON PER DAY AMMONIA PRODUCTION FACILITY	COMPLETE APPLICATION DATE = DATE OF ADMINISTRATIVE COMPLETENESS PSD-LA-768(M-1), ISSUED OCTOBER 14, 2013, CORRECTED THE CAPACITY OF THE AMDEA TANK (2009-F), REVISED THE EMISSION LIMITATIONS FOR THE AMMONIA STORAGE FLARE (2202-B), AND ADDED STARTUP EMISSIONS ATTRIBUTED TO THIS FLARE TO THE PERMIT. THESE CHANGES ARE REFLECTED IN THIS RBLC ENTRY.	PRIMARY REFORMER FURNACE (101-B)	11.39	NATURAL GAS	956.2	MM BTU/HR	NATURAL GAS: 613.5 MM BTU/HR PURIFIER WASTE GAS: 326.1 MM BTU/HR HIGH PRESSURE FLASH GAS: 10.4 MM BTU/HR LP SCRUBBER OVERHEAD: 6.2 MM BTU/HR	Carbon Dioxide Equivalent (CO2e)	P	Energy efficiency measures: process integration and improved combustion measures (i.e., combustion tuning, optimization using parametric testing, installation of advanced digital instrumentation).	490025	TPY	ANNUAL MAXIMUM	BACT-PSD	

Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide And Process Contains 'heater'
Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Carbon Dioxide And Process Contains 'boiler'

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY DESCRIPTION	PERMIT_NOTES	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
*FL-0330	PORT DOLPHIN ENERGY LLC		Port Dolphin is a deepwater port designed to moor liquefied natural gas shuttle and regasification vessels 28 miles off the cost of Florida.		Boilers (4 - 278 mmbtu/hr each)	11.31	natural gas	0			Carbon Dioxide	P	tuning, optimization, instrumentation and controls, insulation, and turbulent flow.	117	LB/MMBTU	8-HOUR ROLLING AVERAGE	BACT-PSD	Emission limit if for CO2-equivalent (CO2e)
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Carbon Dioxide	P	good operating practices & use of natura gas	117	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Carbon Dioxide	P	proper operation and use of natural gas	117	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS		
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Carbon Dioxide	P	good operating practices & use of natura gas	117	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Carbon Dioxide	P	proper operation and use of natural gas	117	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS		
*IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	ALSO SIC: 2819 NAICS: 211112	TWO (2) AUXILIARY BOILERS	11.31	NATURAL GAS	408	MMBTU/H, EACH	IDENTIFIED AS EU-005A AND EU-005B. ALSO COMBUSTS SUBSTITIUTE NATURAL GAS (SNG)	Carbon Dioxide	P	USE OF NATURAL GAS OR SNG; ENERGY EFFICIENT BOILER DESIGN (UTILIZING AN ECONOMIZER, CONDENSATE RECOVERY, INLET AIR CONTROLS AND BLOWDOWN HEAT RECOVERY.);	81	% THERMAL EFFICIENCY		BACT-PSD	EMISSION LIMIT CONT: 81% THERMAL EFFICIENCY (HHV)
*IN-0166	INDIANA GASIFICATION, LLC	INDIANA GASIFICATION, LLC	THE PERMITTEE OWNS AND OPERATES A STATIONARY SUBSTITUTE NATURAL GAS (SNG) AND LIQUEFIED CARBON DIOXIDE (CO2) PRODUCTION PLANT ALSO SIC: 2819 NAICS: 211112	ALSO SIC: 2819 NAICS: 211112	FIVE (5) GASIFIER PREHEAT BURNERS	19.6	NATURAL GAS AND SNG	35	MMBTU/H, EACH	IDENTIFIED AS EU-008A THROUGH EU-008E. ALSO COMBUSTS SUBSTITUTE NATURAL GAS (SNG).	Carbon Dioxide	P	USE OF GOOD ENGINEERING DESIGN; THE USE OF NATURAL GAS OR SNG.	6438	T/YR	TWELVE CONSECUTIVE MONTHS	BACT-PSD	
*SC-0142	SHOWA DENKO CARBON, INC.		GRAPHITE ELECTRODE MANUFACTURING FACILITY.		HOT OIL HEATER	19.6	NATURAL GAS	5	MMBTU/H	THERE WILL BE A HOT OIL HEATER FOR THE MILL, MIX, AND EXTRUSION PROCESS AND A HOT OIL HEATER FOR THE PITCH IMPREGNATION PROCESS (EACH SIZED AT 5 MMBTU/HR).	Carbon Dioxide	N	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	3093	T/YR (CO2E)		BACT-PSD	
*SC-0142	SHOWA DENKO CARBON, INC.		GRAPHITE ELECTRODE MANUFACTURING FACILITY.		PITCH IMPREGNATION/PREHEATER	19.6	NATURAL GAS	12	MMBTU/H		Carbon Dioxide	N	GOOD COMBUSTION PRACTICES, ANNUAL TUNE UP, LOW NOX BURNERS	7424	T/YR (CO2E)		BACT-PSD	
AK-0076	POINT THOMSON PRODUCTION FACILITY	EXXON MOBIL CORPORATION	Oil Gas exploration and production facility	Establish a new facility in the North Slope of Alaska	Combustion of Fuel Gas	16.15	Fuel Gas	7520	kW	7.52 MW with Dry Low NOx and SoLoNOx Technology burning natural gas on the North Slope of Alaska, north of the Artic Circle	Carbon Dioxide	P	DLN with inlet heating and good combustion practices	0			BACT-PSD	
AL-0231	NUCOR DECATUR LLC	NUCOR CORPORATION	THE FACILITY PRODUCES STEEL COILS PRIMARILY FROM STEEL SCRAP USING THE ELECTRIC ARC FURNACE (EAF) PROCESS.	FACILITYWIDE EMISSIONS CONTINUED: PB - 1.5 T/YR	VACUUM DEGASSER BOILER	13.31	NATURAL GAS	95	MMBTU/H		Carbon Dioxide	N		0.061	LB/MMBTU		BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	ROLLING 30 DAY AVERAGE	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	ROLLING 30 DAY AVERAGE	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Carbon Dioxide	P	good combustion practices	117	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).	AUXILIARY BOILER (AUX-1)	11.31	NATURAL GAS	338	MMBTU/H		Carbon Dioxide	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	117	LB/MMBTU		BACT-PSD	
SC-0113	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS, LLC	PYRAMAX CERAMICS PLANS TO CONSTRUCT A MANUFACTURING FACILITY FOR THE PRODUCTION OF PROPPANT BEADS FOR USE IN THE OIL AND GAS INDUSTRY. THE MAJOR RAW MATERIAL IS CLAY. THE CLAY IS MIXED WITH CHEMICALS AND THEN FIRED IN A KILN TO PRODUCE CERAMIC BEADS. INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.	INITIAL CONSTRUCTION PERMIT FOR A GREENFIELD FACILITY.	BOILERS	13.31	NATURAL GAS	5	MMBTU/H	THE CONSTRUCTION PERMIT AUTHORIZES THE CONSTRUCTION OF TWO (2) IDENTICAL BOILERS. THIS PROCESS AND POLLUTANT INFORMATION IS FOR ONE SINGLE BOILER.	Carbon Dioxide	A	CONTROL METHOD FOR CO2E: GOOD DESIGN AND COMBUSTION PRACTICES.	0			BACT-PSD	RECORD TYPE AND QUANTITY OF FUEL CONSUMED.
TX-0627	LONE STAR NGL MONT BELVIEW GAS PLANT(LONE STAR)	ENERGY TRASFER PARTNERS, LP (ETP)	ETP is authorized to constuct the four natural gas processing plants and associated compression equipments at the existin Jckson County Gas Plant located in Granado, Texas.		Plant Heater System	11.31	Natural Gas	48.5	MMBTU/H	There are four (4) plants and each plant has exactly 4 heaters of various throughputs: - Hot oil Heater of 48.5 MMBTU/H, - Trim Heater of 17.4 MMBTU/H, - Molecular Sieve regeneration Heater of 9.7 MMBTU/H, - Triethylene Glycol Dehydration Regeneration Heater of 3 MMBTU/H.	Carbon Dioxide	N		1102.5	LB/MMSCF CO2	365-DAY ROLLING AVG.	BACT-PSD	Numeric limit is summation of 4 heaters in each of the four (4) plants Plant 1: H-1706, H-7810, H-7820 and H-7410. Plant 2: H-2706, H-7811, H-7821 and H-7411. Plant 3: H-3706, H-7812, H-7822 and H-7412. Plant 4: H-4706, H-7813, H-7823 and H-7413.
TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	The proposed 10th Furnace Project williinlude constructing a new furnace capabble of cracking naphtha, ethane, propane, and tutane.		Ethylene Cracking Furnace No. 10	11.31	Natural gas or process fuel gas	498	MMBTU/H		Carbon Dioxide	A	Selective Catalytic Reduction systm.	255735	T/YR	12-MONTH ROLLING AVERAGE	BACT-PSD	Flue Gas Exhaust Temperature should less than or equal to 309 degree F.
TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	The proposed 10th Furnace Project williinlude constructing a new furnace capabble of cracking naphtha, ethane, propane, and tutane.		Stem Package Boilers	11.39	Natural Gas and Fuel gas	425.4	MMBTU/H	2 Steam Package Boilers (Same Throughput):IDs: N-24A and N-24B	Carbon Dioxide	A	Selective Catalytic Reduction Controls (SCR)	420095	T/YR	12-MONTH ROLLING AVG BASIS	BACT-PSD	BACT limits are for each of the two unit N-20A and N-20B.
TX-0629	BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	The proposed 10th Furnace Project williinlude constructing a new furnace capabble of cracking naphtha, ethane, propane, and tutane.		Gas Turbine Auxiliary Duct Burners	12.31	Natural gas	310.4	MMbtu/H	For Process IDs:N-20A and N-20B.	Carbon Dioxide	A	Selective Catalytic Reduction Control (SCR).	117786	T/YR	365-DAY ROLLING AVERAGE.	BACT-PSD	The permittee shall maintain a minimum overall thermal efficiency of 60% on a 12?month rolling average basis, calculated monthly.

Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Methane And Process Contains 'heater'
Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Methane And Process Contains 'boiler'

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY DESCRIPTION	PERMIT NOTES	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Methane	P	good operating practices & use of natural gas	0.0023	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Methane	P	proper operation and use of natural gas	0.0023	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Methane	P	good combustion practices	0.0023	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Methane	P	good operating practices & use of natural gas	0.0023	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Methane	P	proper operation and use of natural gas	0.0023	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).	AUXILIARY BOILER (AUX-1)	11.31	NATURAL GAS	338	MMBTU/H		Methane	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0022	LB/MMBTU		BACT-PSD	

Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Nitrous Oxide (N2O) And Process Contains 'heater'
Permit Date Between 01/01/2003 And 10/28/2013 And Pollutant Name is Nitrous Oxide (N2O) And Process Contains 'boiler'

RBLCID	FACILITY NAME	CORPORATE OR COMPANY NAME	FACILITY DESCRIPTION	PERMIT NOTES	PROCESS NAME	PROCCESS TYPE	PRIMARY FUEL	THROUGHPUT	THROUGHPUT UNIT	PROCESS NOTES	POLLUTANT	CONTROL METHOD CODE	CONTROL METHOD DESCRIPTION	EMISSION LIMIT 1	EMISSION LIMIT 1 UNIT	EMISSION LIMIT 1 AVG TIME CONDITION	CASE-BY-CASE BASIS	POLLUTANT COMPLIANCE NOTES
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Nitrous Oxide (N2O)	P	good operating practices & use of natural gas	0.0006	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Nitrous Oxide (N2O)	P	proper operation and use of natural gas	0.0006	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Auxiliary Boiler	11.31	natural gas	472.4	MMBTU/H		Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
IA-0105	IOWA FERTILIZER COMPANY	IOWA FERTILIZER COMPANY	Nitrogeneous Fertilizer Manufacturing		Startup Heater	12.31	Natural gas	110.12	MMBTU/H		Nitrous Oxide (N2O)	P	good combustion practices	0.0006	LB/MMBTU	AVERAGE OF 3 STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Startup Heater	13.31	natural gas	58.8	MMBTU/hr	Limited to 5.76 MMCF of natural gas/yr	Nitrous Oxide (N2O)	P	good operating practices & use of natural gas	0.0006	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
*IA-0106	CF INDUSTRIES NITROGEN, LLC - PORT NEAL NITROGEN COMPLEX	CF INDUSTRIES NITROGEN, LLC	Nitrogenous fertilizer manufacturing including ammonia, urea, and urea-ammonium nitrate (UAN) solutions.		Boilers	11.31	natural gas	456	MMBTU/hr	There are two (2) identical boilers	Nitrous Oxide (N2O)	P	proper operation and use of natural gas	0.0006	LB/MMBTU	AVERAGE OF THREE (3) STACK TEST RUNS	BACT-PSD	
LA-0254	NINEMILE POINT ELECTRIC GENERATING PLANT	ENTERGY LOUISIANA LLC	1827 MW POWER PLANT (PRE-PROJECT). NATURAL GAS IS PRIMARY FUEL; NO. 2 & NO. 4 FUEL OIL ARE SECONDARY FUELS. PROJECT INVOLVES DECOMMISSIONING OF 2 BOILERS AND THE CONSTRUCTION OF 2 COMBINED CYCLE GAS TURBINES WITH DUCT BURNERS, A NATURAL GAS-FIRED AUXILIARY BOILER, A DIESEL GENERATOR, 2 COOLING TOWERS, A FUEL OIL STORAGE TANK, A DIESEL-FIRED FIREWASTER PUMP, AND AN ANHYDROUS AMMONIA TANK. FUELS FOR THE TURBINES INCLUDE NATURAL GAS, NO. 2 FUEL OIL, AND ULTRA LOW SULFUR DIESEL.	APPLICATION ACCEPTED RECEIVED DATE = DATE OF ADMINISTRATIVE COMPLETENESS BACT FOR GREENHOUSE GASES (CO2E) FROM THE COMBINED CYCLE TURBINE GENERATORS (UNITS 6A & 6B) IS OPERATING PROPERLY AND PERFORMING NECESSARY ROUTINE MAINTENANCE, REPAIR, AND REPLACEMENT TO MAINTAIN THE GROSS HEAT RATE AT OR BELOW 7630 BTU/KW-HR (HHV) (ANNUAL AVERAGE).	AUXILIARY BOILER (AUX-1)	11.31	NATURAL GAS	338	MMBTU/H		Nitrous Oxide (N2O)	P	PROPER OPERATION AND GOOD COMBUSTION PRACTICES	0.0002	LB/MMBTU		BACT-PSD	

Appendix C

Detailed Process Flow Diagrams

F	CORRECTED SHOWING E-3869 DELETED FROM SYSTEM & REVISED VT-2002 TRAYS				
	RJM	17-JUN-14	RJM	KAE	JRB
E	REVISED HOT OIL CONTROLS @ E-3868, REVISED HC LIQUIDS FROM VKO-2004				
	RJM	13-JUN-14	RJM	KAE	JRB
G	DIESEL STRIPPER REBOILER OPTION AND ADDED VACUUM DEGASSING				
	RJM	05 AUG 14	RJM	KAE	JRB
REVISION NUMBER	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY

MAGELLAN MIDSTREAM PARTNERS, L.P.

PFD - CONDENSATE STRIPPER
PREHEAT & PREFLASH SECTION
SHEET 1

CORPUS CHRISTI TX

leidos

DRAWN BY	JSA	SCALE NONE	A.F.E.
DATE DRAWN	10/17/13	DRAWING NO.	
CHECKED BY	RJM	475-D-102	G
PROJECT ENGINEER	KAE		
APPROVED BY	JRB		

F 475-D-102

F	DIESEL STRIPPER REBOILER OPTION AND ADDED VACUUM DEGASSING				
	RJM	05 AUG 14	RJM	KAE	JRB
E	MOVED CONTROL VALVE @ AC-3004, REVISED HOT OIL CONTROLS @ E-3871				
	RJM	13-JUN-14	RJM	KAE	JRB
D	ISSUED FOR DESIGN				
	JSA	4 APR 14	RJM	KAE	JRB
REVISION NUMBER	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY

MAGELLAN[SM]
MIDSTREAM PARTNERS, L.P.

PFD - CONDENSATE SPLITTER
MAIN FRACTIONATOR SECTION
SHEET 2

CORPUS CHRISTI TX

leidos

DRAWN BY	JSA	SCALE NONE	A.F.E.
DATE DRAWN	10/17/13	DRAWING NO.	
CHECKED BY	RJM	475-D-102	F
PROJECT ENGINEER	KAE		
APPROVED BY	JRB		

REVISION NUMBER	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY
F	REVISED VT-2004 & VT-2005				
	RJM	17-JUN-14	RJM	KAE	JRB
E	ADD BYPASS @ AC-3009, REV. HOT OIL CONTROLS @ E-3873 & E-3875				
	RJM	13-JUN-14	RJM	KAE	JRB
D	ISSUED FOR DESIGN				
	JSA	4 APR 14	RJM	KAE	JRB

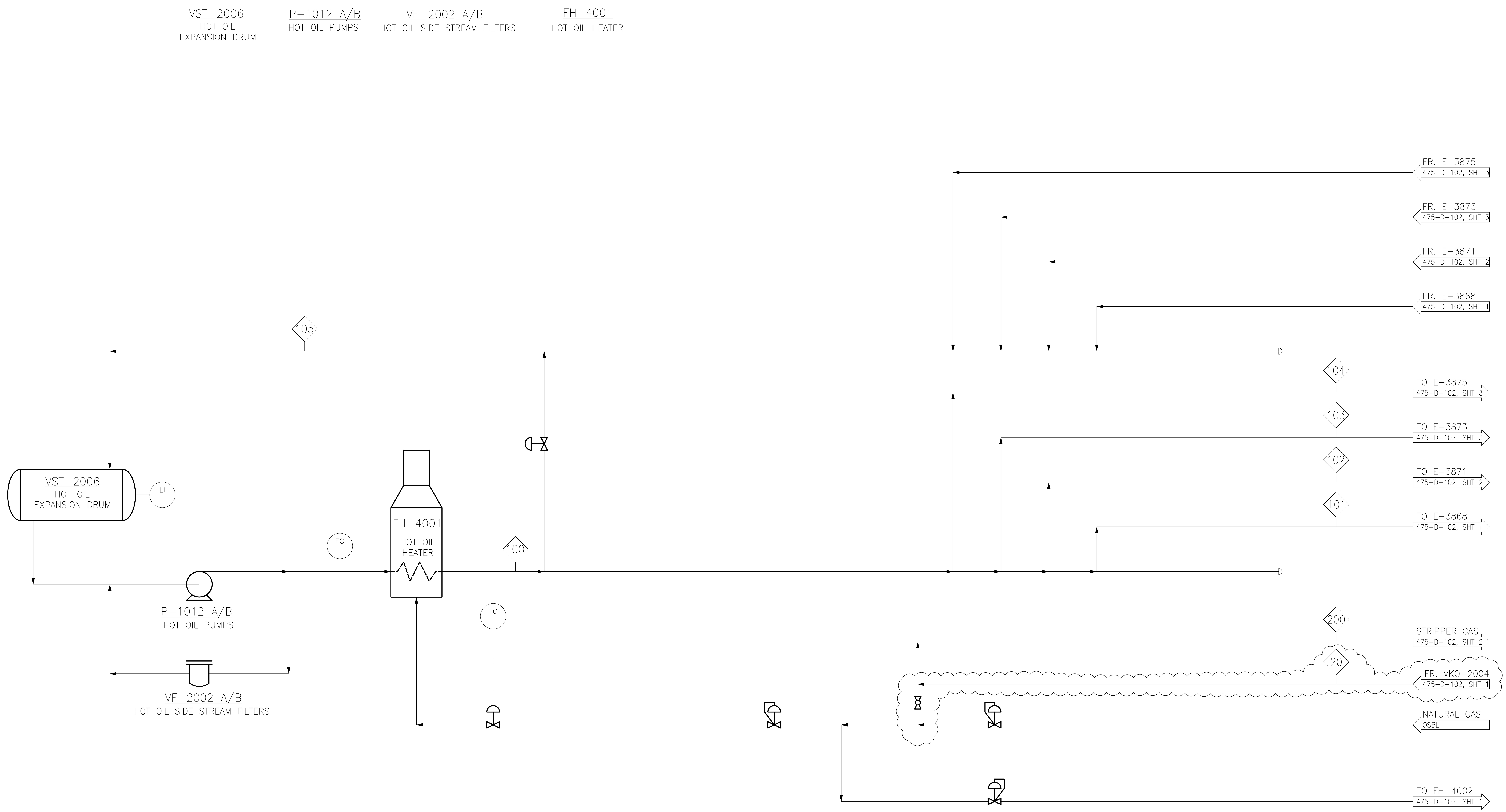
MAGELLAN MIDSTREAM PARTNERS, L.P.

PFD - CONDENSATE SPLITTER
DEPROPANIZER & DEBUTANIZER SECTION
SHEET 3

CORPUS CHRISTI TX

leidos

DRAWN BY	JSA	SCALE NONE	A.F.E.
DATE DRAWN	10/17/13	DRAWING NO.	
CHECKED BY	RJM	475-D-102	
PROJECT ENGINEER	KAE		
APPROVED BY	JRB		F



REVISION NUMBER	DESCRIPTION	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY
C	PROCESS DESIGN REVIEW	JSA	24 JAN 14	RJM	KAE	JRB
E	CHANGED DESTINATION OF STREAM "20"	JSA	19 DEC 13			
D	ISSUED FOR DESIGN	JSA	4 APR 14	RJM	KAE	JRB

MAGELLAN℠ MIDSTREAM PARTNERS, L.P.

PFD - CONDENSATE SPLITTER
UTILITY SECTION
SHEET 4

CORPUS CHRISTI TX

DRAWN BY	JSA	SCALE NONE	A.F.E.
DATE DRAWN	10/30/13	DRAWING NO.	
CHECKED BY	RJM	475-D-102	E
PROJECT ENGINEER	KAE		
APPROVED BY	JRB		

leidos

AC-3006	P-101X A/B	VKO-200	C-1002 A/B
ATB COOLER	DEGASSED ATB PUMPS	DEGASSING DRUM	DEGASSING VACUUM PUMPS

REVISION NUMBER	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY
A	ADDED VACUUM DEGASSING EQUIPMENT (NEW SHEET)				
	RJM	05 AUG 14	RJM	KAE	JRB

MAGELLAN℠
MIDSTREAM PARTNERS, L.P.

PFD - CONDENSATE STRIPPER
VACUUM FLASH SYSTEM
SHEET 5

CORPUS CRISTI TX

DRAWN BY	RJM	SCALE NONE	A.F.E.
DATE DRAWN	8/5/14	DRAWING NO.	
CHECKED BY	RJM	475-D-102	
PROJECT ENGINEER	KAE		
APPROVED BY	JRB		A