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Application for U.S. Environmental Protection Agency Greenhouse Gas Air Quality Permit

Magellan Terminals Holdings, L.P.
Corpus Christi Terminal
Corpus Christi, Nueces County, Texas

RN102536836
CN600134639

November 2013

RPS

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November 11, 2013 FedEx No.: 7971 2849 7744

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

Re: Application for PSD Air Quality Permit
Greenhouse Gas Emissions
Magellan Terminals Holdings, L.P.
Corpus Christi Terminal
Corpus Christi, Nueces County
Customer Reference Number: CN600134639
Regulated Entity Number: RN102536836

Dear Mr. Robinson:

On behalf of KM Magellan Terminals Holdings, L.P. (MTH), RPS is hereby submitting the enclosed application for a Prevention of Significant Deterioration (PSD) air quality permit for greenhouse gas (GHG) emissions from the proposed 100,000 barrel per day condensate splitter facility at the MTH Corpus Christi Terminal. The proposed project is subject to PSD review for GHG, for which the Texas Commission on Environmental Quality (TCEQ) has not implemented a PSD permitting program. MTH will pursue authorization for other pollutants through the TCEQ. This document constitutes an application from MTH 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.

We wish to thank you in advance for you consideration of this application. If you should have any questions during your review, please feel free to contact me at (512) 879-6672 or Ms. Stacy Colpitt of MTH at (918) 574-7726.

Sincerely,

RPS

Robin L. Patrick

Robin L. Patrick
Senior Consultant

RLP/cks

Enclosure

cc: Ms. Stacy Colpitt, Magellan Terminals Holdings, L.P., Tulsa, OK

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Section 1
Introduction

Magellan Terminals Holdings, L.P. (MTH) owns and operates a for-hire bulk petroleum terminal (Corpus Christi Terminal) located in Corpus Christi, Nueces County, Texas. The facility is an existing marine terminal operating under TCEQ New Source Review (NSR) Permit No. 56470 and various Permit-By-Rule (PBR) authorizations. Existing facility operations include storage tanks, heaters, marine loading and unloading, marine VCUs, truck unloading, pipeline connections and other piping components.

1.1 Purpose of this Application

MTH proposes to construct and operate a new 100,000 barrels per day (bbl/day) condensate splitter at the existing Corpus Christi Terminal, to be constructed in two 50,000 bbl/day phases. The proposed condensate splitter will consist of two trains which 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.

Table 1-1 presents a summary of the proposed facility project emissions compared to Greenhouse Gases (GHG) Prevention of Significant Deterioration (PSD) applicability thresholds. The proposed project is subject to PSD review for GHG, for which the TCEQ has not implemented a PSD permitting program. Therefore, this document constitutes an application from MTH 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 project.

1.2 Application Organization

This application is organized into the following sections:

Section 1	presents the application objectives and organization;
Section 2	contains administrative information;
Section 3	contains an Area Map showing the facility location and a Plot Plan for the proposed condensate splitter;
Section 4	contains a process description for the Corpus Christi Terminal splitter project;

Section 5 contains a discussion of the estimated emissions and a completed TCEQ Table 1(a);

Section 6 presents the Best Available Control Technology (BACT) analysis for the facilities included in this application;

Section 7 addresses applicability of the federal GHG PSD permitting requirements;

Section 8 contains an additional impact analysis as required by 40 CFR 52.21(o);

Appendix A contains detailed emissions calculations; and

Appendix B contains the results of the RACT/BACT/LAER Clearinghouse (RBLC) search that supports the heater BACT analysis in Section 6.

Table 1-1
GHG PSD Applicability Analysis Summary
Magellan Corpus Christi Splitter Project

Source	Project Phase	CO2			CH4			N2O			CO2e		
		Baseline	Proposed	Change	Baseline	Proposed	Change	Baseline	Proposed	Change	Baseline	Proposed	Change
		tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy	tpy
Heater H-1A	1	0	24,439.57	24,439.57	0	0.46	0.46	0	0.05	0.05	0	24,464	24,464
Heater H-2A	1	0	54,989.04	54,989.04	0	1.04	1.04	0	0.10	0.10	0	55,043	55,043
Heater H-1B	2	0	24,439.57	24,439.57	0	0.46	0.46	0	0.05	0.05	0	24,464	24,464
Heater H-2B	2	0	54,989.04	54,989.04	0	1.04	1.04	0	0.10	0.10	0	55,043	55,043
Flare	1	0	375.99	375.99	0	0.01	0.01	0	0.00	0.00	0	376	376
Fugitives	1	0	0.00	0.00	0	9.27	9.27	0	0.00	0.00	0	195	195
Vapor Combustor	1	0	9,744.20	9,744.20	0	0.39	0.39	0	0.08	0.08	0	9,777	9,777
MSS	1	0	38.66	38.66	0	0.00	0.00	0	0.00	0.00	0	39	39
Project Increase (tpy)				***169,016.08***			***12.67***			***0.38***			***169,400***
Netting Threshold (tons)				-			-			-			***75,000***
Netting Required (Yes/No)				-			-			-			***Yes***
Contemporaneous Period Change (tons)				-			-			-			***>75,000***
Significant Modification Threshold (tons)				-			-			-			***75,000***
Federal Review Required (Yes/No)				-			-			-			***Yes***

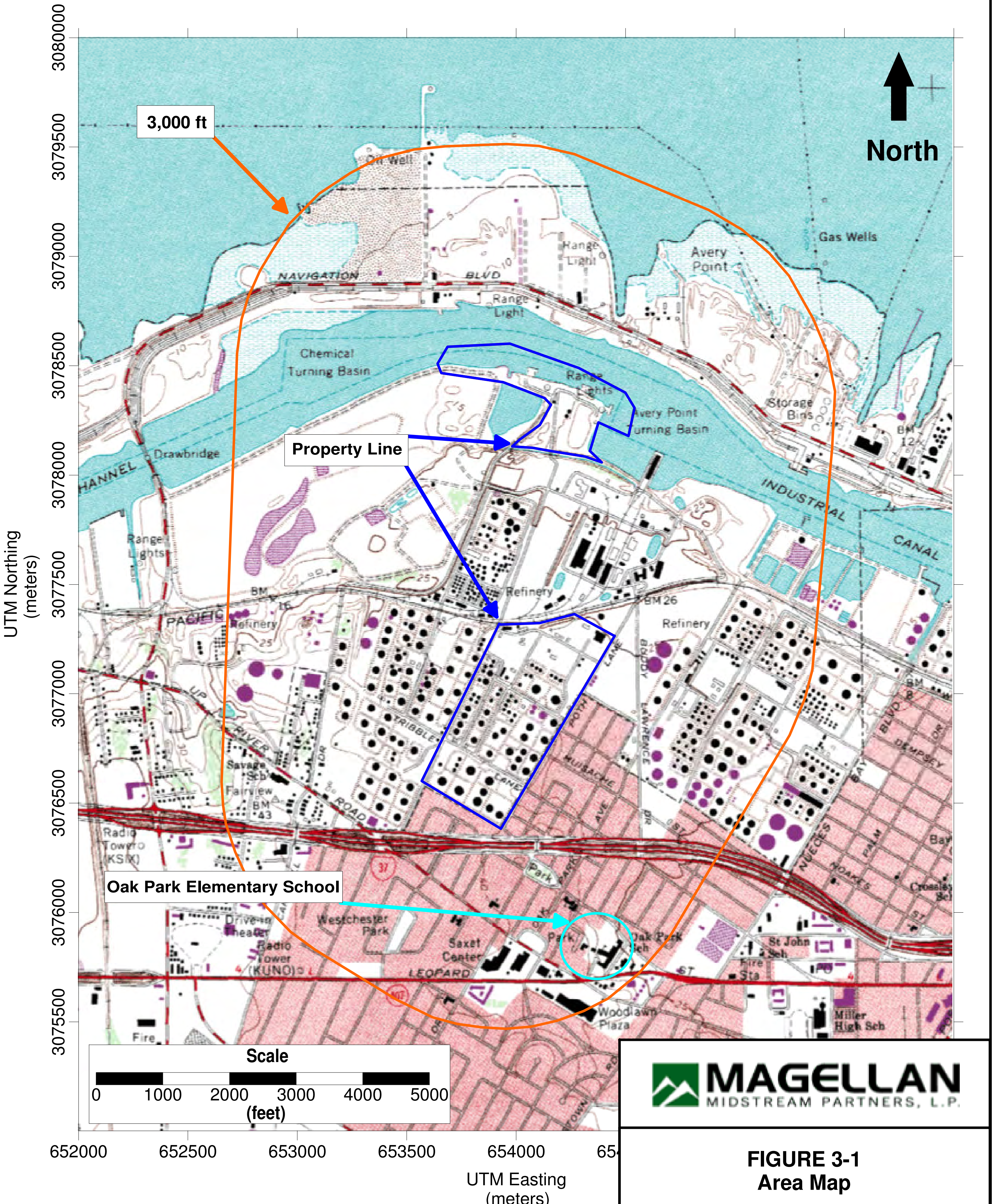
Section 2
Administrative Information

The Administration Form 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 information available. Please note that the project is still in the planning phases and therefore the information used to develop this application is subject to change.

Air Quality Application Administrative Information			
Company or Other Legal Name: Magellan Terminals Holdings, L.P.			
Company Official Contact Name: Ms. 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. Stacy Colpitt			
Title: Air Specialist			
Mailing Address: One Williams Center, MD 27			
City: Tulsa	State: OK	ZIP Code: 74172	
Telephone No.: 918-574-7726	Fax No.: 918-574-7760	E-mail Address: stacy.colpitt@magellanlp.com	
Site Name: Corpus Christi Terminal			
Area Name/Type of Facility: Condensate Splitter			☒ Permanent ☐ Portable
Principal Company Product or Business: Petroleum Bulk Stations and Terminals			
Principal Standard Industrial Classification Code (SIC): 4226			
Principal North American Industry Classification System (NAICS): 49319			
Projected Start of Construction Date: November 2014			
Projected Start of Operation Date: January 2016			
Facility Street Address: 1802 Poth Ln			
City/Town: Corpus Christi	County: Nueces	ZIP Code: 78407	
Latitude (nearest second): 27° 48' 29.34"		Longitude (nearest second): 97° 26' 12.25"	
Customer Reference Number (CN): CN600134639			
Regulated Entity Number (RN): RN102536836			
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: MELANIE A. LITTLE			
Signature: Melanie A. Little Vice-President, Operations *Original Signature Required* 11/8/13			
Date:			

Section 3
Area Map and Plot Plan

An area map is provided in Figure 3-1 which details the 3,000-foot and one-mile distance markings. A detailed plot plan for the proposed condensate splitter and the associated facilities is provided in Figure 3-2.



MAGELLAN MIDSTREAM PARTNERS, L.P.

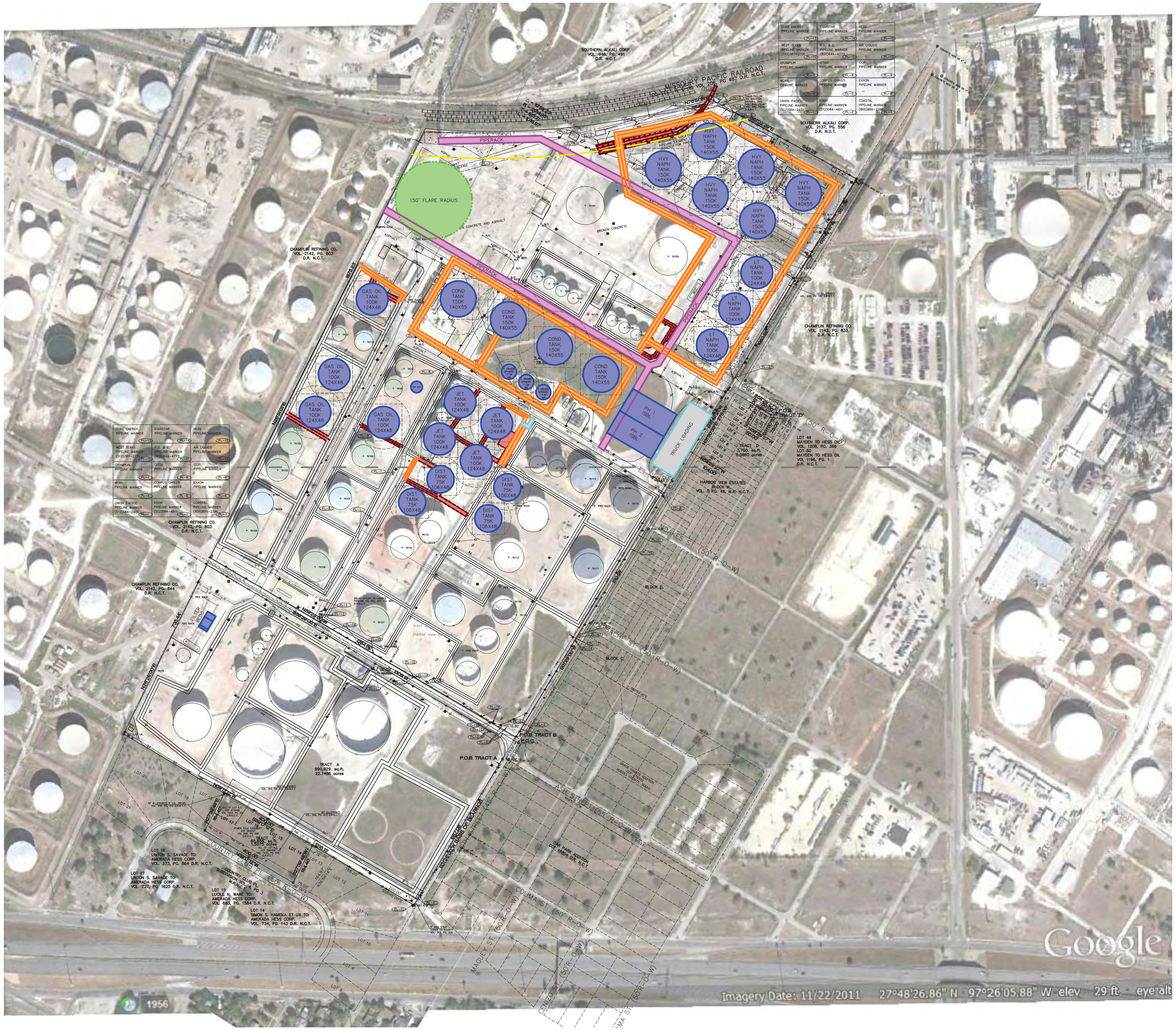
FIGURE 3-1
Area Map

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

SK-001 | 1



GRAPHIC SCALE

100 0 100 200

(IN FEET)
1 inch = 100 ft.

REVISION NUMBER	DRAWN BY	DATE REVISED	CHECKED BY	PROJECT ENGINEER	APPROVED BY
1					

MAGELLAN MIDSTREAM PARTNERS, L.P.

MAGELLAN TERMINALS HOLDINGS, L.P.

Figure 3-2
Proposed Condensate Splitter Plot Plan

Section 4
Project and Process Description

The MTH Corpus Christi Terminal is a for-hire bulk petroleum storage terminal. Petroleum products and specialty chemicals are stored in various storage tanks and transferred in and out of the terminal tankage for external customers via pipeline, tank truck, and marine vessel. The facility consists of various storage tanks and associated piping, loading, and control equipment. The proposed condensate splitter facility to be installed in the terminal in Corpus Christi, Texas, will process 100,000 bbls/day of a hydrocarbon condensate material 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. Initially there will be one train (Phase I). An identical train (Phase II) will be installed in the future following completion of Phase I. The process described in the following paragraphs utilizes conventional distillation technology to accomplish this.

The hydrocarbon condensate is fed from storage tanks to the pre-flash column where the lightest fraction of the condensate is distilled from the overhead at a pressure which will typically permit complete condensation. Any incondensable material that may be produced will be used for fuel gas in the heaters. Free water that may be present in the feed will be flashed in the pre-fractionation column and produced from the pre-flash accumulator water boot. The overhead liquid product from the pre-flash column, Y-Grade, will be sent to a pressurized storage sphere. The feed to this pre-flash column is preheated by cross heat exchange with hot streams from the fractionator. This will reduce overall heat input to the unit from fired heating. The bottoms stream from the pre-fractionation column is pressured through downstream heat exchangers into the main fractionation column.

This main fractionation column separates the bottoms from the pre-fractionation column into five products. These products include light naphtha, heavy naphtha, kerosene/jet fuel, diesel, and resid (gas oil). Light naphtha is recovered from the fractionator accumulator. The heavy naphtha, kerosene, and diesel are recovered from the column as side streams. These streams are then fed to the top trays of individual stripping columns. Lighter material is stripped from the product draw in each of these side columns by introducing heat to the bottom of each stripper column. The stripped side draw vapors are returned to the main fractionation column from the overhead of each stripper column and the stripped side draw products are used to preheat the feed to the process before final cooling and transfer to storage.

The fractionator bottoms product, resid (gas oil), is then cross exchanged with feed to the column, further cooled, and then sent to storage. This product represents the heaviest fraction and condensate. Lighter material is removed from the bottoms product in the lower stripping section of the column. The overhead condensing system will be operated at the lowest practical pressure to minimize temperatures and improve separation. Both a liquid distillate product and a non-condensable gas stream saturated with heavier components will be produced from the overhead vapor along with column reflux. The off-gas will be compressed and sent to fuel gas.

Condensate feed, the Y-Grade product, light naphtha, heavy naphtha, kerosene/jet fuel, diesel, and resid are all stored in tanks onsite. The Y-Grade product and light naphtha will be stored in pressurized tanks due to the high vapor pressure of the material. Condensate, heavy naphtha, kerosene/jet fuel, and diesel are stored in internal floating roof tanks. The products will be stored at elevated temperatures (approximately 120°F) except condensate which will be at atmospheric temperature. Resid (gas oil) will be stored in fixed roof insulated tanks and may be heated to maintain the temperature at or above 150°F.

In addition to the main process equipment just described there are certain support processes that are required. An elevated flare is provided for use in emergency overpressure situations to dispose of excess process vapors. This flare utilizes a continuous pilot to ensure that unexpected release events result in safe disposal.

Existing docks will be utilized to transfer products offsite. Y-Grade product will be transferred under pressure to tank trucks at a new loading rack. All of the products may be transferred to local refineries and terminals via existing pipelines.

A process flow diagram is included as Figure 4-1.

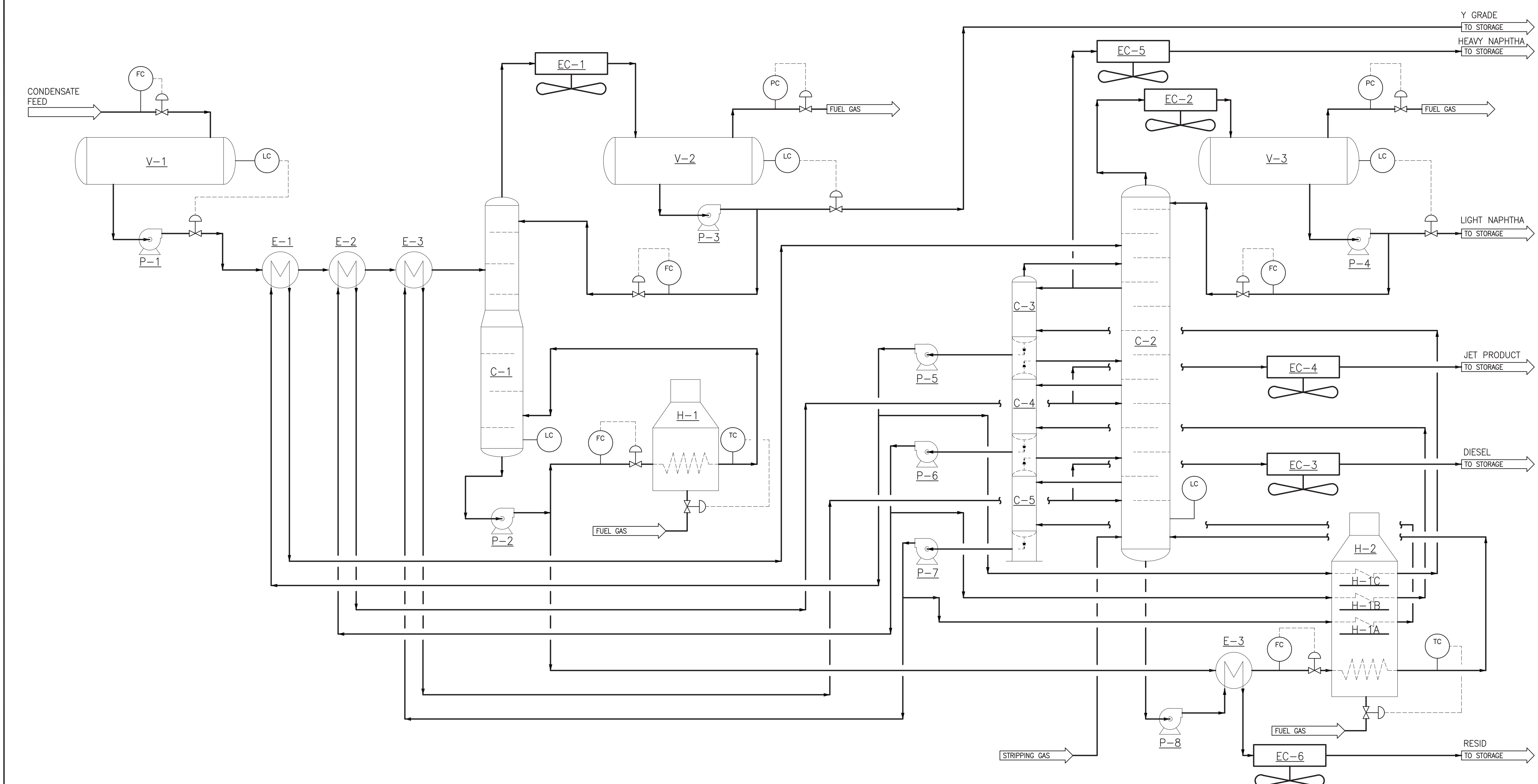


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Figure 4-1
Process Flow Diagram

DWG NO	TITLE	REV	CKD	APP	DATE	DESCRIPTION
REFERENCE DRAWINGS						REVISIONS

Drawn	Date	Scale NONE	Proj no 2151328000	Rev
Checked	Eng app	Design	Dwg no D-001	----
Filename CONDENSATE SPLITTER.DWG				

P:\FDB\1650-TUL\IND\2151328000_MMP_CondSpltrSchedA\20_DESGN\40_CAD\PIPING\FLOW DIAGRAMS\CONDENSATE SPLITTER.dwg Oct 03, 2013 - 8:02am richardsden

Section 5
GHG Emissions Summary

This section contains the completed TCEQ Table 1(a) showing the GHG emissions rates for the facilities included in this application. The GHGs emitted from the proposed facilities include carbon monoxide (CO_2), methane (CH_4), and nitrous oxide (N_2O). MTH 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;
- Storage Tanks;
- Fugitives; and
- Marine Vessel and Tank Truck Loading.

5.1.1 Heaters

The new condensate splitter process will include two natural gas fired heaters for each train. Gas produced by the splitter process will also contribute to the total heat input to the heaters. Heater GHG emission calculations are included in Appendix A as Table A-1. Short-term (pound per hour) emissions are based on the maximum firing rate and annual (ton per year) emissions are based on an annual average firing rate. GHG emission factors for CO_2, CH_4, and N_2O were taken from 40 CFR Part 98, Subpart C, Tables C-1 and C-2.

The annual average emissions are calculated in order to establish an emission cap and the representations are not meant to be taken as operational limits for the individual heaters. MTH only represents that the sum of the GHG emissions from the heaters will comply with the annual cap based on managing operation and good combustion practices.

5.1.2 Flare

The new condensate splitter plant will utilize a process flare which is designed for control of venting during planned MSS and upset situations. 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. Flare pilot GHG emission calculations are included in Appendix A as Table A-2. GHG emissions associated with anticipated MSS activities controlled via the process flare are discussed in Section 5.2.6.

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 Storage Tanks

The new condensate splitter plant includes sixteen floating roof storage tanks, four fixed roof storage tanks, and seven pressurized storage tanks for Phases I and II combined. Based on the contents of the proposed tanks, GHG emissions associated with routine working and breathing emissions have been determined to be negligible; therefore, GHG emission estimates for the proposed tanks are not included in this GHG PSD permit application.

5.1.4 Fugitives

The new condensate splitter plant will contain process piping components. Fugitive GHG emission calculations are included in Appendix A as Table A-3. 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.*

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 VOC 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. MTH will implement the 28VHP LDAR program for fugitive components associated with the proposed condensate splitter plant. The CH_4 emissions were then calculated by multiplying the total controlled emission rate by the weight percent of CH_4 in the process streams. To ensure the GHG emission calculations are conservative in the absence of detailed stream speciation information, the CH_4 concentration was assumed to be 100%. Although this is a highly conservative assumption, fugitive GHG emissions are negligible compared to the GHG emission rates from fuel combustion; therefore, this assumption has no significant impact on the total project GHG emissions.

5.1.5 Marine Vessel and Tank Truck Loading

Condensate splitter plant product 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. The loading of such liquids in pressurized tank trucks is possible because the material in the tank can evaporate or condense as liquid levels change to accommodate liquid level changes without venting.

Marine loading will be used to transport other condensate splitter plant products from the facility. Marine loading emissions are collected using a vacuum system and controlled using two existing marine vapor combustion units (VCUs).

The GHG emission calculations from the marine loading operations are included in Appendix A as Tables A-4 through A-5. VOC emissions resulting from loading activities were calculated 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/lbmole
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 controlled VOC emissions for products with a vapor pressure greater than 0.5 psia will utilize a vapor collection system that is routed to a control device with a minimum destruction efficiency of 99.5%. GHG emissions associated with the combustion of VOC loading emissions were estimated using the annual total heat input 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.

5.2 Maintenance, Startup, and Shutdown Emissions

This application only addresses the GHG MSS emissions associated with the facilities included in this application. Table A-6 in Appendix A provides a summary of the GHG MSS emissions included in this application. GHG MSS emissions are only expected to be generated during controlled storage tank roof landings. Other MSS activities including heater maintenance; process vessel and piping maintenance; vacuum truck operations; and frac tanks are not expected to use combustion control and therefore will not generate GHG emissions.

5.2.1 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 (hereafter referred to in this application as AP-42).

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* (L_{SL}), occur daily as long as the floating roof remains landed.

If MTH 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 34,000 parts per million by volume (ppmv) as methane after which the tank may vent to atmosphere. These emissions are referred to as *degassing losses*. A second step taken for landings where MTH plans to enter a tank is cleaning using forced ventilation. Blowers are used to ventilate the tank and force out any residual VOC material.

Additional emissions occur when incoming stock liquid fills a tank with a landed roof. The incoming volume of liquid not only displaces an equivalent volume of vapors from below the floating roof, but also generates its own set of product vapors that are displaced during the filling process. These two types of emissions are collectively referred to as *filling losses* (L_{FL}).

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.

Tank design considerations impact both standing idle and filling loss emissions. Therefore, AP-42 separates floating roof tanks into the following three categories for emissions determination purposes:

- Internal floating roof (IFR) tanks with a full or partial heel;
- External floating roof (EFR) tanks with a full or partial heel; and
- IFR and EFR tanks that drain dry.

AP-42 presents standing idle and filling loss equations for each tank category listed above.

Common data to all emission calculations are the physical tank parameters, meteorological data, and the physical properties of the materials being stored. Meteorological data was taken from the Tanks 4.0 database. The calculation methodology used to estimate the standing losses, degassing, forced ventilation, and refilling emissions is discussed in further detail below.

5.2.2 Standing Idle Losses

Similar to breathing losses under normal operating conditions, standing idle losses occur during that period of time a roof is landed with product still in the tank. 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.

For IFR tanks designed to be drain-dry, standing losses [lbs] are calculated using Equation 2-22 from AP-42:

$$L_{SL} = 00063 W_l \left(\frac{\pi D^2}{4} \right)$$

Where:

W_l = stock liquid density, lb/gal
D = tank diameter, ft

The standing losses cannot physically exceed the available stock liquid in the tank. Therefore, an upper limit to the standing losses [lbs] is provided in Equation 2-24 from AP-42:

$$L_{S\,L} \leq 0.60 \left(\frac{P V_V}{RT} \right) M_V$$

Where:

P = true vapor pressure of the liquid inside the tank, psia
V_V = volume of the vapor space, ft^3
R = ideal gas constant, 10.731 psia ft^3 / lb-mol °R
T = average temperature of the vapor and liquid below the floating roof, °R
M_V = stock vapor molecular weight, lb/lb-mol

5.2.3 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. After the tank is stripped, the vapor space is degassed and the vapors collected and controlled with a system that is at least 98% efficient in reducing VOC emissions.

The first component of the degassing emission estimate is 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.

The second component of the emission estimate is from venting the tank to atmosphere after it is degassed to a concentration of 34,000 ppmv (as methane). The second component of the emissions was calculated by assuming that one landed tank volume at an initial concentration of 34,000 ppmv (3.4%) is vented to the atmosphere.

5.2.4 Storage Tank Forced Ventilation

Forced ventilation emissions are generated by air moving across the surface of residual liquid in the tank. Forced ventilation emissions are estimated using the following equation from Ajay Kumar, N.S. Vatcha, and John Schmelzle as published in "Estimate Emissions from Atmospheric Releases of Hazardous Substances," Environmental Engineering World, November-December 1996:

$$L_{FV} = 0.0000414 U_S^{0.78} P_V M_W^{0.67} A_P^{0.94}$$

Where:

U_S = surface wind speed [meters/second]
P_V = vapor pressure [Pa]
M_W = vapor molecular weight
A_P = service area [square meters]

5.2.5 Refilling Losses

Similar to loading losses, refilling losses occur while a tank is being filled with product during that period of time a roof is landed. 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 the following calculation from Equation 2-26 from AP-42:

$$L_{FL} = \left(\frac{PV_V}{RT}\right) M_V S$$

Where:

P = true vapor pressure of the liquid inside the tank, psia
V_V = volume of the vapor space, ft^3
R = ideal gas constant, 10.731 psia ft^3 / lb-mol °R
T = average temperature of the vapor and liquid below the floating roof, °R
M_V = stock vapor molecular weight, lb/lb-mol
S = filling saturation factor (0.15 for drain-dry)

5.2.6 Roof Landing Vapor Control System

When the storage tanks included in this application store liquids with a vapor pressure greater than 0.5 psia and degassing is required, MTH proposes to control the resulting vapors using a flare or equivalent combustion device in a manner consistent with good engineering practice. GHG emission estimates are based on the annual total heat input 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.

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 proposed condensate splitter project will consist of two trains which will each process 50,000 bbls/day of a hydrocarbon condensate material to obtain products suitable for commercial use. In general, the products (Y-Grade, Light Naphtha, Heavy Naphtha, Jet Kerosene, Diesel, and Resid/Gas Oil) will be produced by a distillation process. The majority of the GHG emissions associated with the proposed project are the result of the energy required for this distillation process. Specifically, 159,013 tpy CO_2e of the proposed project emissions of 169,400 tpy CO_2e (94%) are generated from the H-1A, H-1B, H-2A, and H-2B heaters associated with the distillation, for Phase I and II combined. This BACT analysis will focus primarily on the CO_2 emissions from the proposed heaters.

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

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

1) Identification of available control technologies;

2) Technically infeasible alternatives are eliminated from consideration;

3) Remaining control technologies are ranked by control effectiveness;

4) Evaluation of control technologies for cost-effectiveness, energy impacts, and environmental effects in order of most effective control option to least effective; and

5) Selection of BACT.

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

6.1 Heaters (EPNs: H-1A, H-1B, H-2A, and H-2B)

GHG emissions, primarily CO_2, are generated from the combustion of natural gas in the proposed heaters. CO_2e emissions from heaters will be calculated based on metered gas consumption, emission factors from 40 CFR 98, Tables C-1 and C-2, and global warming potential factors from 40 CFR 98, Table A-1.

6.1.1 Step 1 – Identification of Potential Control Technologies

The following technologies are available for controlling GHG emissions from the proposed heaters:

- ***Fuel Selection:*** Natural gas has the lowest carbon intensity of any available fuel for the proposed heaters. Incondensable material produced by the splitter process may also be used as heater fuel; therefore, reducing purchased natural gas usage.

- ***Carbon Capture and Sequestration:*** In EPA's recent GHG BACT guidance, EPA takes the position that, *"for the purpose of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology that is "available" for large CO_2e emitting facilities including fossil fuel-fired power plants and industrial facilities with high purity CO_2 streams*".

- ***Heater/Process Design***: The heaters will be designed to use efficient burners; efficient heat transfer/recovery efficiency; and 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.

- ***Good Combustion Practices:*** Good fuel/air mixing in the combustion zone through the use of oxygen monitors to optimize the fuel/air mixture and limit excess air.

- ***Periodic Burner Tune-up:*** The burners will be tuned periodically to maintain optimal thermal efficiency.

- ***Product Heat Recovery:*** Hot product streams are cooled with exchange of heat with the colder feed and the distillation column's stripping section to provide process heat in lieu of heat from the furnace.

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 search results are presented in Appendix C. No additional technologies were identified. The control methods listed in the RBLC were limited to burner tune-ups, good design, and good combustion control and operation. Information from *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR Guide for Energy Plant Managers* (Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008) was also used in the preparation of this analysis.

6.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

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% GHG emission reduction for fuels containing no carbon),
- CO_2 capture and storage (up to 90% GHG emission reduction),
- Heater/process design (up to 10% GHG emission reduction),
- Good combustion practices (5-25% GHG emission reduction),
- Periodic tune-up (up to 10% for boilers GHG emission reduction, information not found for heaters), and
- Product heat recovery (does not directly improve heater efficiency).

Virtually all GHG emissions from fuel combustion are a result of 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 a chemical process and 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. Coke oven gas is not a viable fuel for the proposed heaters because the Corpus Christi Terminal does not include 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%. Hydrogen fuel, in any concentration, is not a readily available fuel for most industrial facilities and is only a viable low carbon fuel at industrial plants that generate hydrogen internally. 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.

The most effective control method is carbon capture and storage, which is potentially capable of a 90% reduction of produced CO_2 emissions. Good heater/process design, good combustion practices, and periodic tune-ups are all considered effective and have a range of efficiency improvements which cannot be directly quantified; therefore, the above ranking is approximate only. 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 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 (i.e., a distillation column) which reduces the heat required from process heaters. Where the product streams require cooling, this practice also reduces the energy required to cool the product stream.

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

Use of Low Carbon (Natural Gas) 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. Natural gas is the lowest carbon fuel available and a very clean burning fuel with respect to criteria pollutants, thus is has a 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; MTH 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.

There are no negative environmental, economic, or energy impacts associated with this control technology.

Carbon Capture and Sequestration: As stated in Section 6.1.2, carbon capture and sequestration (CCS) is not considered to be a feasible 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, EPA 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 application are similar in nature to the gas-fired industrial boiler in the EPA Guidance Appendix F example and are not high-purity CO_2 streams. Furthermore, a GHG application submitted by KM Liquids Terminals LLC for a very similar condensate splitter project at their Galena Park Terminal reviewed CCS as a potential control method. That evaluation, which included a comparison against the Indiana Gasification Project and an order of magnitude cost analysis for CCS, demonstrated that CCS is not an appropriate control method for condensate splitter facilities. Since the proposed facility is not one of the listed facility types for which CCS should be considered, and based on the results of the review completed by KM Liquids Terminals LLC, MTH has determined that CCS is not a viable control option for the proposed project.

Heater/Process Design: New heaters will be designed with efficient burners, more efficient heat transfer efficiency, 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. In addition, 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 product stream may be used as a heater fuel source thus reducing purchased natural gas usage. There are no negative environmental, economic, or energy impacts associated with this control technology.

Good Combustion Practices: Some amount of excess air is required to ensure complete fuel combustion, minimize emissions, and enhance safety; however, too much excess air will reduce overall heater efficiency. Good fuel/air mixing in the combustion zone will be achieved through the use of oxygen monitors to optimize the fuel/air mixture and limit excess air. Manual or automated air/fuel ratio controls are used to optimize 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 MTH'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 annually;
- Preventive maintenance check of oxygen control analyzers per manufacturer;
- Cleaning of burner tips on an as-needed basis; and
- Cleaning of convection section tubes on an as-needed basis.

These activities ensure maximum thermal efficiency is maintained. Although it is not possible to quantify an efficiency improvement, convection cleaning has shown improvements in the 0.5-1.5% range. There are no negative environmental, economic, or energy impacts associated with this control technology.

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. Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream. This will also reduce the energy requirement (primarily purchased electricity) needed to cool the product streams. Figure 4-1 in Section 4 of this permit application identifies points in the process where this technology will be used. There are no negative environmental, economic, or energy impacts associated with this control technology.

6.1.5 Step 5 – Selection of BACT

MTH 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 (Natural Gas) Fuel:*** The proposed heaters will use natural gas fuel as it is the lowest carbon purchased fuel available for use at the facility.
- ***Heater/Process Design***: The heaters will be designed to maximize heat transfer efficiency and reduce heat loss.
- ***Good Combustion Practices:*** MTH will operate the heaters using good combustion practices as described above.
- ***Periodic Heater Tune-ups:*** MTH will maintain analyzers and clean heater burner tips and convection tubes as needed
- ***Product Heat Recovery:*** Excess heat in product streams will be used to pre-heat feed streams throughout the process through the use of heat exchangers to transfer the heat from the product stream to the feed stream.

6.2 Flare (EPN: FL-1)

GHG emissions, primarily CO_2, are generated from the combustion of natural gas used to maintain the flare pilots. CO_2e emissions from flaring activities will be calculated based on metered pilot/assist gas consumption, waste gas combustion, and standard emission factors and/or fuel composition and mass balance.

6.2.1 Step 1 – Identification of Potential Control Technologies

The available control technologies for flare operation include:

- ***Use of a thermal oxidizer/vapor combustion unit (VCU) in lieu of a flare:*** Alternate control technology consideration.

- ***Use of a vapor recovery unit (VRU) in lieu of a flare:*** Alternate control technology consideration.

- ***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 and a thermocouple on the flare stack. The flare purge rate will be determined by the manufacturer. Visual opacity monitoring will occur when the flare is operating.

6.2.2 Step 2 – Elimination of Technically Infeasible Alternatives

One of the primary reasons that a flare is considered for control of VOC is that it can be used for emergency releases. Although efforts are made to prevent or reduce 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 vapor recovery unit was used for control of routine vent streams, a flare would still be necessary to control emergency releases and would require continuous burning of natural gas in the pilots, which would result in additional CO_2, NOx, and CO emissions. Therefore, the use of either a thermal oxidizer/VCU or VRU is rejected as technically infeasible for the proposed project. Both flaring minimization and proper operation of the flare are technically feasible.

6.2.3 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.

6.2.4 Step 4 – Evaluation of Control Technologies in Order of Most Effective 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. MTH 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 reduced fuel costs. This control technology goes not cause any negative environmental, economic, or energy impacts.

6.2.5 Step 5 – Selection of BACT

MTH proposes to incorporate all of the control options identified in Section 6.2.1, 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 and a thermocouple on the flare stack. The flare purge rate will be determined by the manufacturer. Visual opacity monitoring will occur when the flare is operating.

6.3 Storage Tanks

The new condensate splitter plant includes sixteen floating roof storage tanks, four fixed roof storage tanks, and seven pressurized storage tanks. Based on the contents of the proposed tanks, routine working and breathing GHG emissions have been determined to be negligible; therefore, a GHG BACT analysis for the proposed tanks are not included in this GHG PSD permit application. Storage tank GHG emissions associated with MSS activities are addressed in Section 6.5 of this application.

6.4 Process Fugitives (EPN: FUG)

Hydrocarbon emissions from leaking piping components (process fugitives) associated with the proposed project include methane, a GHG. The additional methane emissions from process fugitives have been conservatively estimated to be 195 tpy as CO_2e. Compared to other sources in the splitter process, the emission contribution from fugitives is negligible (0.1% of total CO_2e emissions); however, for completeness, they are addressed in this BACT analysis.

6.4.1 Step 1 – Identification of Potential Control Technologies

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

6.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

6.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

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

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

Although technically feasible, use of an LDAR program to control GHG emissions that occur as process fugitives is cost prohibitive. However, implementation of an LDAR program for VOC control purposes will also result in effective control of the small amount of GHG emissions from the same piping components. MTH currently implements TCEQ's 28M LDAR program at the Corpus Christi Terminal. Due to the emission increase from the added components, MTH will upgrade its monitoring program to follow TCEQ's 28VHP LDAR in order to minimize process fugitive VOC emissions. There are no negative environmental, economic, or energy impacts associated with implementing TCEQ's 28VHP LDAR program.

6.4.5 Step 5 – Selection of BACT

Considering the minimal amount of GHG emissions from process fugitives, implementation of an LDAR program is not cost effective and BACT is determined to be no control. However, MTH will implement TCEQ's 28VHP LDAR program for VOC BACT purposes, which will also effectively minimize GHG emissions. Therefore, the proposed VOC LDAR program more than satisfies GHG BACT requirements.

6.5 Marine Vessel and Tank Truck Loading

Vapors generated by loading products with a vapor pressure of 0.5 psia or greater from the proposed condensate splitter are controlled by the marine VCUs. Natural gas assist 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. CO_2e emissions from loading activities will be calculated based on metered pilot/assist gas consumption, waste gas combustion, and standard emission factors and/or fuel composition and mass balance.

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 (i.e., 99%) than flares (i.e., 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 the availability of space to construct new VRUs is limited.

For these reasons, the use of either a flare or vapor recovery unit are rejected as technically infeasible for the proposed project. Both minimization and proper operation of the VCU are technically feasible.

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).

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. Truck loading operations are conducted under pressure and will not generate emissions.

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^{o}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 Effective 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^{o}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 recoded 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

MTH 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.

6.7 Maintenance, Startup, and Shutdown Activities (EPN: MSS)

GHG emissions, primarily CO_2, are generated from the combustion of VOC vapors associated with MSS activities (i.e., storage tank roof landings) 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. MTH plans to use a flare or other combustion device providing equivalent destruction efficiency (such as a vapor combustion unit or engine) for control of MSS emissions. CO_2e emissions from MSS activities will be calculated based on metered pilot/assist gas consumption, waste gas combustion, and standard emission factors and/or fuel composition and mass balance.

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 a VRU in lieu of a flare/VCU:*** VRU systems (i.e., carbon canisters, scrubbers, etc.) 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 or internal combustion engine (ICE):*** 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 VRU, 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 VRU 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 or ICE (not directly quantifiable for MSS activities).

Proper operation of a VRU 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 is not applicable to VRU technology.

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, VCU, and/or ICE 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 Effective to Least Effective

Use of a VRU. VRU technology for MSS emissions control could be implemented for vacuum trucks, frac tanks, etc. The availability of a VRU as a control method is limited based on flow rates and event duration. Specifically, a VRU is 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/ICE operation for the proper destruction of VOCs ensures that excess natural gas is not unnecessarily combusted. This added advantage of reducing fuel costs makes this control option cost effective as both a criteria pollutant and GHG emission control option. There are no negative environmental, economic, or energy impacts associated with this control technology.

6.7.5 Step 5 – Selection of BACT

MTH proposes to incorporate the remaining control options identified in Section 6.6.1 as BACT for controlling GHG MSS emissions from the proposed condensate splitter plant. These technologies proposed for MSS activities are listed below:

- ***Use of a VRU in lieu of a flare/VCU:*** VRU systems (i.e., carbon canisters, scrubbers, etc.) 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 of ICE:*** 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.

Section 7
GHG PSD Applicability

Prevention of Significant Deterioration (PSD) permitting is required for a modification of an existing major source for each attainment pollutant and other regulated pollutants (such as H_2S and H_2SO_4) for which the modification will result in a significant net emissions increase. The GHG emission increases associated with this permit application are summarized and compared to the PSD applicability thresholds in Table 1-1 at the end of Section 1. Included at the end of this section are the applicable Table 1F and Table 2F. Nueces is designated attainment/unclassified for GHG PSD permitting purposes.

The Corpus Christi Terminal is a petroleum storage and transfer facility with a total storage capacity exceeding 300,000 barrels and currently subject to PSD for VOC. Therefore, the GHG limit for PSD applicability is 75,000 tpy CO_2e. There are no significant decreases of GHG emissions in the contemporaneous period that could potentially result in the proposed project netting out of GHG PSD review; therefore, detailed GHG contemporaneous netting is not included as part of this application. Therefore, the proposed condensate splitter facility triggers PSD review for GHG emissions.

As a result of a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the GHG permitting requirements in Texas and EPA assumed the role as the GHG permitting authority for Texas GHG permits. GHG emissions associated with the proposed condensate splitter project are currently subject to the jurisdiction of the EPA.

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**	Application Submittal Date: **November 11, 2013**
Company: **Magellan Terminals Holdings, L.P.**	
RN: **102536836**	Facility Location: **1802 Poth Lane**
City: **Corpus Christi**	County: **Nueces**
Permit Unit I.D.:	Permit Name:
Permit Activity: New Source ___ Modification X	**GHG Permit for Condensate Splitter Facility**

Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**	
	GHG	
Nonattainment?	**No**	
Existing site PTE (tpy)?	**< 100,000**	
Proposed project emission increases (tpy from 2F[2])?	**169,400**	
Is the existing site a major source?	**Yes**	
If not, is the project a major source by itself?	**NA**	
If site is major, is project increase significant?	**Yes**	
If netting required, estimated start of construction?	**November 2014**	
Five years prior to start of construction	**November 2009**	contemporaneous
Estimated start of operation	**January 2016**	period
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	**> 75,000**	
Major NSR Applicable?	**Yes**	

Melanie A. Rittle	VP, Operations	11/8/13
Signature	Title	Date

1. Other pollutants. [Pb, H2S, TRS, H2SO4, Fluoride excluding HF, etc.]
2. Sum of proposed emissions minus baseline emissions, increases only.

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

TCEQ - 10154 (Revised 04/12) Table 1F
These forms are for use by facilities subject to air quality permit requirements and may be revised periodically. (APDG 5912v1)

Table 2F - CO_{2e}
Project Emission Increase

Pollutant[1]: CO2e	Permit No.: TBD
Baseline Period: NA	

	Affected or Modified Facilities FIN	EPN	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)
1	H-1A	H-1A	-	-	-	24,464	-	24,464	-	24,464
2	H-2A	H-2A	-	-	-	55,043	-	55,043	-	55,043
3	H-1B	H-1B	-	-	-	24,464	-	24,464	-	24,464
4	H-2B	H-2B	-	-	-	55,043	-	55,043	-	55,043
5	FL-1	FL-1	-	-	-	376	-	376	-	376
6	FUG1	FUG1	-	-	-	195	-	195	-	195
7	VCU1/VCU2	VCU1/VCU2	-	-	-	9,777	-	9,777	-	9,777
8	MSS	MSS	-	-	-	39	-	39	-	39
9	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	-	-
18	-	-	-	-	-	-	-	-	-	-
19	-	-	-	-	-	-	-	-	-	-
20	-	-	-	-	-	-	-	-	-	-
21	-	-	-	-	-	-	-	-	-	-
22	-	-	-	-	-	-	-	-	-	-
23	-	-	-	-	-	-	-	-	-	-
24										
									Page Subtotal:	*169,400*

Section 8
Additional Impact Analysis

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

> (1) The owner or operator shall provide an analysis of the impairment to visibility, soils and vegetation that would occur as a result of the source or modification and general commercial, residential, industrial and other growth associated with the source or modification. The owner or operator need not provide an analysis of the impact on vegetation having no significant commercial or recreational value.
>
> (2) The owner or operator shall provide an analysis of the air quality impact projected for the area as a result of general commercial, residential, industrial and other growth associated with the source or modification.
>
> (3) The Administrator may require monitoring of visibility in any Federal Class I area near the proposed new stationary source for major modification for such purposes and by such means as the Administrator deems necessary and appropriate.

This section of the application addresses these requirements.

8.1 Visibility, Soils, and Vegetation

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

8.2 Associated Growth

The proposed project will not significantly affect residential, commercial, or industrial growth in the area. Only 20 new jobs are expected to be created by the proposed project. Even if these jobs were to be filled by individuals relocating to the area, it would result in a negligible impact on the existing infrastructure. Because these impacts will be negligible, the corresponding impact on air quality will also be negligible.

8.3 Visibility Monitoring

The nearest Federal Class I Area is the Caney Creek Wilderness Area in Arkansas, which is approximately 525 km from the facility. The proposed particulate emissions are below the PSD major modification threshold and will not have an impact on this area.

Appendix A

Routine Emission Calculation Details

Table A-1
Heater Emissions
Magellan Corpus Christi Splitter Project
November 2013

Source	Pollutant	Short-Term Emission Factor (lb/MMBtu)	Emission Factor[1] (lb/MMBtu)	Emissions (tpy)	GWP[2]	CO2e (tpy)
Heater H-1A	CO2	1.17E+02	1.17E+02	**24439.57**	1	**24439.57**
	N2O	2.20E-04	2.20E-04	**0.05**	310	**14.29**
	CH4	2.20E-03	2.20E-03	**0.46**	21	**9.68**
Heater H-2A	CO2	1.17E+02	1.17E+02	**54989.04**	1	**54989.04**
	N2O	2.20E-04	2.20E-04	**0.10**	310	**32.15**
	CH4	2.20E-03	2.20E-03	**1.04**	21	**21.78**
Heater H-1B	CO2	1.17E+02	1.17E+02	**24439.57**	1	**24439.57**
	N2O	2.20E-04	2.20E-04	**0.05**	310	**14.29**
	CH4	2.20E-03	2.20E-03	**0.46**	21	**9.68**
Heater H-2B	CO2	1.17E+02	1.17E+02	**54989.04**	1	**54989.04**
	N2O	2.20E-04	2.20E-04	**0.10**	310	**32.15**
	CH4	2.20E-03	2.20E-03	**1.04**	21	**21.78**

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-2
Flare Pilot Emissions
Magellan Corpus Christi Splitter Project
November 2013

Pilot Gas Usage =	12	scf/min
	1020	btu/scf, based on LHV
	0.73	MMBtu/hr
	6,433.34	MMBtu/yr

Combusted Material	Pollutant	Emissions Factor[1] (Value)	(Units)	Emissions (ton/yr)	GWP[2]	CO2e (ton/yr)
Natural Gas	CO2	53.02	kg/MMBtu	375.99	1	375.99
	CH4	0.001	kg/MMBtu	0.01	21	0.15
	N2O	0.0001	kg/MMBtu	0.00	310	0.22

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. Heat input (MMBtu/yr) = pilot gas flow rate (scf/min) x natural gas heat content (1,020 But/scf) x (1 MMBtu / 10^6 Btu) x (525,600 min/yr)

Table A-3
Fugitive Component Emissions
Magellan Corpus Christi Splitter Project
November 2013

Component Type	Stream Type	Emission Factor SOCMI Without C2	Number of Components	28VHP Control Efficiency	Hourly Emissions (lb/hr)	Annual Emissions (tpy)
Valves	Gas/Vapor	0.0089	100	97%	0.03	0.12
	Light Liquid	0.0035	1,000	97%	0.11	0.46
	Heavy Liquid	0.0007	100	0%	0.07	0.31
Pumps	Light Liquid	0.0386	30	85%	0.17	0.76
	Heavy Liquid	0.0161	30	0%	0.48	2.12
Flanges	Gas/Vapor	0.0029	100	30%	0.20	0.89
	Light Liquid	0.0005	3,000	30%	1.05	4.60
	Heavy Liquid	0.00007	100	30%	0.00	0.02
				Total Fugitive Emissions	***2.12***	***9.27***
				Total Fugitive CO2e Emissions	***44.44***	***194.66***

Notes:
1. Piping component fugitive emissions conservatively assumed to consist of 100% CH4 for GHG PSD applicability purposes.
2. CO2e annual emission rate (tpy) = CH4 emission rate (tpy) x CH4 GWP

Table A-4
Marine Loading Emissions
Magellan Corpus Christi Splitter Project
November 2013

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.

										Uncollected Fugitives EPN: LOADFUG		Controlled Emissions EPNs: VCU1/VCU2	
Material	**Vessel Type**	**Collection Efficiency (%)**	**Control Efficiency (%)**	**MW**	**Temp (°F)**	**Vapor Pressure (psia)**	**Loading Loss Factor (lb/1000 gal)**	**Throughput (bbl/hr)**	**Throughput (bbl/yr)**	**lbs/hr**	**tpy**	**lbs/hr**	**tpy**
Light Naphtha	Barge	100%	99.5%	65	120	18.81	13.1355	20,000	19,874,250	0.00	0.00	55.17	27.41
Heavy Naphtha	Ship	95%	99.5%	90	120	1.90	0.7365	20,000	30,714,750	30.93	23.75	2.94	2.26
Low VP Group	Barge	0%	0%	130	120	0.045	0.0628	20,000	58,201,440	52.78	76.80	0.00	0.00

Table A-5
Marine Loading Control - Vapor Combustor
Magellan Corpus Christi Splitter Project
November 2013

Operation Type	Annual	
	Loading Vapors MMBtu/yr	Natural Gas MMBtu/yr
Barge/Ship Loading	118,671	0.00

Combusted Material	Pollutant	Emissions Factor[1]		Emissions	GWP[2]	CO2e
		(Value)	(Units)	(ton/yr)		(ton/yr)
Natural Gas	CO2	53.02	kg/MMBtu	0.00	1	0.00
	CH4	0.0010	kg/MMBtu	0.00	21	0.00
	N2O	0.01%	kg/MMBtu	0.00	310	0.00
Loaded Material	CO2	74.4900	kg/MMBtu	9,744.20	1	9744.20
	CH4	0.003	kg/MMBtu	0.39	21	8.24
	N2O	0.0006	kg/MMBtu	0.08	310	24.33

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 natural gas heat content (1,020 But/scf) x (1 MMBtu / 10^6 Btu) x (8,760 hr/yr)

Table A-6
Storage Tank Landing Emission Calculations
Magellan Corpus Christi Splitter Project
November 2013

Constants			
Atmospheric Pressure	Pa	psia	14.70
Zero wind speed rim seal loss factor	K_{Ra}	lbmole/ft-yr	6.7
Wind speed rim seal loss factor	K_{Rb}	lbmole/(mph)^n-ft-yr	0.2
Seal-related wind speed exponent	n		3.0
Product factor	K_C	(1.0 for non-crude)	1.0
Control Device			Flare
Control Device Efficiency	CE		98%
Degassing Turnovers			4
Degassing Air Flow Rate		cfm	300
Degassing Saturation Factor			0.5

Combustion Device Emission Factors			
Pollutant	High Btu	Low Btu	Units
NOx	0.138	0.0641	lb/MMBtu
CO	0.2755	0.5496	lb/MMBtu

Green House Gas Emission Factors				
40 CFR 98 Name	Material Name	kg CO2/MMBtu	kg CH4/mmBtu	kg N2O/mmBtu
Distillate	Distillate	73.96	0.003	0.0006
Naphtha	Heavy Naphtha	68.02	0.003	0.0006
Kerosene-Type Jet Fuel	Jet	72.22	0.003	0.0006
Crude Oil	Condensate	74.49	0.003	0.0006

Tank Landing Data																		
			Phase 1 Tanks									Phase 2 Tanks						
		Tank EPN	PH1C1	PH1C2	PH1HN1	PH1HN2	PH1HN3	PH1J1	PH1J2	PH1D1	PH1D2	PH2D1	PH2D2	PH2HN1	PH2J1	PH2J2	PH2D1	PH2D2
Tank Type			IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR	IFR
Diameter	D	ft	163	163	210	210	210	134	134	134	115	163	163	190	134	134	115	115
Landed Roof Leg Height		ft	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6	6
Month of Landing Event			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
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
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
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
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
Days Off-Float (before degas/clean)	n_d	day	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Tank Heel Status [(1)]			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
Product Stored			Condensate	Condensate	Heavy Naphtha	Heavy Naphtha	Heavy Naphtha	Jet	Jet	Distillate	Distillate	Condensate	Condensate	Heavy Naphtha	Jet	Jet	Distillate	Distillate
RVP			10	10	1.2	1.2	1.2	---	---	---	---	10	10	1.2	---	---	---	---
Slope of ASTM Distillation Curve			3	3	2.5	2.5	2.5	---	---	---	---	3	3	2.5	---	---	---	---
Molecular Weight - vapor	M_V	lb/lbmole	66	66	80	80	80	130	130	130	130	66	66	80	130	130	130	130
Molecular Weight - liquid	M_L	lb/lbmole	92	92	176	176	176	162	162	188	188	92	92	176	162	162	188	188
Stock Liquid Density	W_l	lb/gal	7.5	7.5	7	7	7	7	7	7.1	7.1	7.5	7.5	7	7	7	7.1	7.1
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
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
Height of Vapor Space	h_v	ft	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Volume of Vapor Space	V_V	ft^3	125,183	125,183	207,782	207,782	207,782	84,602	84,602	84,602	62,311	125,183	125,183	170,089	84,602	84,602	62,311	62,311
Tank Color			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
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
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
Liquid Bulk Temp.	T_B	deg R	543.67	543.67	579.60	579.60	579.60	579.60	579.60	579.60	579.60	543.67	543.67	579.60	579.60	579.60	579.60	579.60
Daily Average Liquid Surface Temp.	T_{LA}	deg R	546.33	546.33	566.45	566.45	566.45	566.45	566.45	566.45	566.45	546.33	546.33	566.45	566.45	566.45	566.45	566.45
Vapor Pressure Function Constant	A		11.72	11.72	12.64	12.64	12.64	N/A	N/A	N/A	N/A	11.72	11.72	12.64	N/A	N/A	N/A	N/A
Vapor Pressure Function Constant	B		5237.27	5237.27	6954.91	6954.91	6954.91	N/A	N/A	N/A	N/A	5237.27	5237.27	6954.91	N/A	N/A	N/A	N/A
True Vapor Pressure of Liquid	P	psia	8.48	8.48	1.44	1.44	1.44	0.05	0.05	0.03	0.03	8.48	8.48	1.44	0.05	0.05	0.03	0.03
Tank Landing Emissions																		
Standing Idle Losses																		
Vapor Space Expansion Factor	K_E		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Standing Idle Saturation Factor	K_s		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Calculated Standing Idle Losses		lb	985.98	985.98	1,527.45	1,527.45	1,527.45	621.93	621.93	630.81	464.61	985.98	985.98	1,250.36	621.93	621.93	464.61	464.61
Standing Idle Losses	L_{SL}	lb	985.98	985.98	1,527.45	1,527.45	1,527.45	48.85	48.85	36.91	27.19	985.98	985.98	1,250.36	48.85	48.85	27.19	27.19
VOC Emissions		tons/event	4.93E-01	4.93E-01	7.64E-01	7.64E-01	7.64E-01	2.44E-02	2.44E-02	1.85E-02	1.36E-02	4.93E-01	4.93E-01	6.25E-01	2.44E-02	2.44E-02	1.36E-02	1.36E-02
Degassing Losses																		
Tank Degassed?			yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes	yes
Degassing Controlled?			yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes	no	no	no	no
Moles		lbmole	90.54	90.54	24.64	24.64	24.64	0.31	0.31	0.24	0.17	90.54	90.54	20.17	0.31	0.31	0.17	0.17
VOC Mass Vapor	Q	lb/event	5975.82	5975.82	1971.16	1971.16	1971.16	40.71	40.71	30.76	22.66	5975.82	5975.82	1613.58	40.71	40.71	22.66	22.66
Controlled Degas VOC Emissions	E_P	lb/event	119.52	119.52	39.42	39.42	39.42	40.71	40.71	30.76	22.66	119.52	119.52	32.27	40.71	40.71	22.66	22.66
Heat Input From Vapor		MMBtu/event	119.52	119.52	39.42	39.42	39.42	---	---	---	---	119.52	119.52	32.27	---	---	---	---
Total Degassing Volume		ft^3/event	500,730	500,730	831,127	831,127	831,127	338,406	338,406	338,406	249,244	500,730	500,730	680,356	338,406	338,406	249,244	249,244
Heat input to maintain at 300 Btu/scf		MMBtu/event	150.22	150.22	249.34	249.34	249.34	---	---	---	---	150.22	150.22	204.11	---	---	---	---
Heat Input from Assist Gas		MMBtu/event	30.70	30.70	209.91	209.91	209.91	---	---	---	---	30.70	30.70	171.84	---	---	---	---
NOx Emission Factor		lb/MMBtu	0.0641	0.0641	0.0641	0.0641	0.0641	---	---	---	---	0.0641	0.0641	0.0641	---	---	---	---
CO Emission Factor		lb/MMBtu	0.5496	0.5496	0.5496	0.5496	0.5496	---	---	---	---	0.5496	0.5496	0.5496	---	---	---	---
Assist Gas (Propane) Emissions		tons/event	6.98E-03	6.98E-03	4.77E-02	4.77E-02	4.77E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.98E-03	6.98E-03	3.91E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC Emissions		tons/event	5.98E-02	5.98E-02	1.97E-02	1.97E-02	1.97E-02	2.04E-02	2.04E-02	1.54E-02	1.13E-02	5.98E-02	5.98E-02	1.61E-02	2.04E-02	2.04E-02	1.13E-02	1.13E-02
NOx Emissions		tons/event	4.81E-03	4.81E-03	7.99E-03	7.99E-03	7.99E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.81E-03	4.81E-03	6.54E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO Emissions		tons/event	4.13E-02	4.13E-02	6.85E-02	6.85E-02	6.85E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.13E-02	4.13E-02	5.61E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO2 Emissions		tons/event	1.23E+01	1.23E+01	1.87E+01	1.87E+01	1.87E+01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.23E+01	1.23E+01	1.53E+01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CH4 Emissions		tons/event	4.97E-04	4.97E-04	8.25E-04	8.25E-04	8.25E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	4.97E-04	4.97E-04	6.75E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
N2O Emissions		tons/event	9.94E-05	9.94E-05	1.65E-04	1.65E-04	1.65E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	9.94E-05	9.94E-05	1.35E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Post-Control Degassing Emissions																		
Vented VOC after Control	E_C	ton/event	0.09	0.09	0.15	0.15	0.15	0.00	0.00	0.00	0.00	0.09	0.09	0.12	0.00	0.00	0.00	0.00

Table A-6
Storage Tank Landing Emission Calculations

Cleaning with Forced Ventilation																		
		Tank EPN	**PH1C1**	**PH1C2**	**PH1HN1**	**PH1HN2**	**PH1HN3**	**PH1J1**	**PH1J2**	**PH1D1**	**PH1D2**	**PH2D1**	**PH2D2**	**PH2HN1**	**PH2J1**	**PH2J2**	**PH2D1**	**PH2D2**
Tank Cleaned?			Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes	Yes
No. of Blowers			2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
Wind Speed		fps	0.0005	0.0005	0.0003	0.0003	0.0003	0.0007	0.0007	0.0007	0.0010	0.0005	0.0005	0.0004	0.0007	0.0007	0.0010	0.0010
Forced Ventilation Emissions		lb/hr	50.30	50.30	10.55	10.55	10.55	0.39	0.39	0.30	0.28	50.30	50.30	10.22	0.39	0.39	0.28	0.28
Duration		hr	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24	24
Heat Input From Vapor		MMBtu/event	24.15	24.15	5.06	5.06	5.06	0.19	0.19	0.14	0.14	24.15	24.15	4.90	0.19	0.19	0.14	0.14
Total Forced Ventilation Volume		ft^3/event	500,730	500,730	831,127	831,127	831,127	338,406	338,406	338,406	249,244	500,730	500,730	680,356	338,406	338,406	249,244	249,244
Heat input to maintain at 300 Btu/scf		MMBtu/event	150.22	150.22	249.34	249.34	249.34	101.52	101.52	101.52	74.77	150.22	150.22	204.11	101.52	101.52	74.77	74.77
Heat Input from Assist Gas		MMBtu/event	126.07	126.07	244.27	244.27	244.27	101.33	101.33	101.38	74.64	126.07	126.07	199.20	101.33	101.33	74.64	74.64
Assist Gas (Propane) Emissions		lb/event	57.31	57.31	111.03	111.03	111.03	46.06	46.06	46.08	33.93	57.31	57.31	90.55	46.06	46.06	33.93	33.93
Assist Gas Emission Rate		tons/event	0.03	0.03	0.06	0.06	0.06	0.02	0.02	0.02	0.02	0.03	0.03	0.05	0.02	0.02	0.02	0.02
VOC Emissions		tons/event	0.01	0.01	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01	0.01	0.00	0.00	0.00	0.00	0.00
NOx Emissions		tons/event	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
CO Emissions		tons/event	7.01	7.01	11.63	11.63	11.63	4.74	4.74	4.74	3.49	7.01	7.01	9.52	4.74	4.74	3.49	3.49
CO2 Emissions		tons/event	1.23E+01	1.23E+01	1.87E+01	1.87E+01	1.87E+01	8.08E+00	8.08E+00	8.28E+00	6.10E+00	1.23E+01	1.23E+01	1.53E+01	8.08E+00	8.08E+00	6.10E+00	6.10E+00
CH4 Emissions		tons/event	4.97E-04	4.97E-04	8.25E-04	8.25E-04	8.25E-04	3.36E-04	3.36E-04	3.36E-04	2.47E-04	4.97E-04	4.97E-04	6.75E-04	3.36E-04	3.36E-04	2.47E-04	2.47E-04
N2O Emissions		tons/event	9.94E-05	9.94E-05	1.65E-04	1.65E-04	1.65E-04	6.71E-05	6.71E-05	6.71E-05	4.95E-05	9.94E-05	9.94E-05	1.35E-04	6.71E-05	6.71E-05	4.95E-05	4.95E-05
Refilling Losses																		
Month of Refill Event			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
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
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
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
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
Refill Material			Condensate	Condensate	Heavy Naphtha	Heavy Naphtha	Heavy Naphtha	Jet	Jet	Distillate	Distillate	Condensate	Condensate	Heavy Naphtha	Jet	Jet	Distillate	Distillate
Pre-Refill Leg Height		ft	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00	6.00
Height of Vapor Space		ft	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90	5.90
Refill Controlled?			yes	yes	yes	yes	yes	no	no	no	no	yes	yes	yes	no	no	no	no
RVP			10	10	1.2	1.2	1.2	---	---	---	---	10	10	1.2	---	---	---	---
Slope of ASTM Distillation Curve			3	3	2.5	2.5	2.5	---	---	---	---	3	3	2.5	---	---	---	---
Molecular Weight - vapor	M_V	lb/lbmole	66	66	80	80	80	130	130	130	130	66	66	80	130	130	130	130
Molecular Weight - liquid	M_L	lb/lbmole	92	92	176	176	176	162	162	188	188	92	92	176	162	162	188	188
Stock Liquid Density	W_l	lb/gal	7.5	7.5	7	7	7	7	7	7.1	7.1	7.5	7.5	7	7	7	7.1	7.1
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
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
Liquid Bulk Temp.	T_B	deg R	543.67	543.67	579.60	579.60	579.60	579.60	579.60	579.60	579.60	543.67	543.67	579.60	579.60	579.60	579.60	579.60
Daily Average Liquid Surface Temp.	T_{LA}	deg R	546.33	546.33	566.45	566.45	566.45	566.45	566.45	566.45	566.45	546.33	546.33	566.45	566.45	566.45	566.45	566.45
Vapor Pressure Function Constant	A		11.72	11.72	12.64	12.64	12.64	N/A	N/A	N/A	N/A	11.72	11.72	12.64	N/A	N/A	N/A	N/A
Vapor Pressure Function Constant	B		5237.27	5237.27	6954.91	6954.91	6954.91	N/A	N/A	N/A	N/A	5237.27	5237.27	6954.91	N/A	N/A	N/A	N/A
True Vapor Pressure of Liquid	P	psia	8.48	8.48	1.44	1.44	1.44	0.05	0.05	0.03	0.03	8.48	8.48	1.44	0.05	0.05	0.03	0.03
Vapor Space Expansion Factor	K_E		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Standing Idle Saturation Factor	K_s		0.27	0.27	0.69	0.69	0.69	0.99	0.99	0.99	0.99	0.27	0.27	0.69	0.99	0.99	0.99	0.99
Vapor Pressure Function	P*		0.21	0.21	0.03	0.03	0.03	0.00	0.00	0.00	0.00	0.21	0.21	0.03	0.00	0.00	0.00	0.00
Saturation Correction Factor	C_{sf}		---	---	---	---	---	---	---	---	---	---	---	---	---	---	---	---
Filling Losses	L_{FL}	lb	1,792.58	1,792.58	591.29	591.29	591.29	12.21	12.21	9.23	6.80	1,792.58	1,792.58	484.03	12.21	12.21	6.80	6.80
Heat Input From Vapor		MMBtu/event	35.85	35.85	11.83	11.83	11.83	---	---	---	---	35.85	35.85	9.68	---	---	---	---
Total Refilling Volume		ft^3/event	123,117	123,117	204,353	204,353	204,353	83,205	83,205	83,205	61,283	123,117	123,117	167,282	83,205	83,205	61,283	61,283
Heat Input from Assist Gas		MMBtu/event	1.08	1.08	49.48	49.48	49.48	---	---	---	---	1.08	1.08	40.50	---	---	---	---
NOx Emission Factor		lb/MMBtu	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641	0.0641
CO Emission Factor		lb/MMBtu	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496	0.5496
Assist Gas (Propane) Emissions		tons/event	2.46E-04	2.46E-04	1.12E-02	1.12E-02	1.12E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.46E-04	2.46E-04	9.21E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
VOC Emissions		tons/event	1.79E-02	1.79E-02	5.91E-03	5.91E-03	5.91E-03	6.11E-03	6.11E-03	4.61E-03	3.40E-03	1.79E-02	1.79E-02	4.84E-03	6.11E-03	6.11E-03	3.40E-03	3.40E-03
NOx Emissions		tons/event	1.18E-03	1.18E-03	1.96E-03	1.96E-03	1.96E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.18E-03	1.18E-03	1.61E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO Emissions		tons/event	1.01E-02	1.01E-02	1.68E-02	1.68E-02	1.68E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.01E-02	1.01E-02	1.38E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO2 Emissions		tons/event	3.03E+00	3.03E+00	4.60E+00	4.60E+00	4.60E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00	3.03E+00	3.03E+00	3.76E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CH4 Emissions		tons/event	1.22E-04	1.22E-04	2.03E-04	2.03E-04	2.03E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.22E-04	1.22E-04	1.66E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
N2O Emissions		tons/event	2.44E-05	2.44E-05	4.05E-05	4.05E-05	4.05E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00	2.44E-05	2.44E-05	3.32E-05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Tank Landing Emissions																		
		Tank EPN	**PH1C1**	**PH1C2**	**PH1HN1**	**PH1HN2**	**PH1HN3**	**PH1J1**	**PH1J2**	**PH1D1**	**PH1D2**	**PH2D1**	**PH2D2**	**PH2HN1**	**PH2J1**	**PH2J2**	**PH2D1**	**PH2D2**
VOC Emission Rate*		tons/event	7.08E-01	7.08E-01	1.06E+00	1.06E+00	1.06E+00	7.40E-02	7.40E-02	6.16E-02	4.54E-02	7.08E-01	7.08E-01	8.64E-01	7.40E-02	7.40E-02	4.54E-02	4.54E-02
Propane Emission Rate		tons/event	7.22E-03	7.22E-03	5.90E-02	5.90E-02	5.90E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	7.22E-03	7.22E-03	4.83E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
NOx Emission Rate		tons/event	6.00E-03	6.00E-03	9.96E-03	9.96E-03	9.96E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.00E-03	6.00E-03	8.15E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO Emission Rate		tons/event	5.14E-02	5.14E-02	8.54E-02	8.54E-02	8.54E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00	5.14E-02	5.14E-02	6.99E-02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CO2 Emission Rate		tons/event	1.54E+01	1.54E+01	2.33E+01	2.33E+01	2.33E+01	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.54E+01	1.54E+01	1.91E+01	0.00E+00	0.00E+00	0.00E+00	0.00E+00
CH4 Emission Rate		tons/event	6.19E-04	6.19E-04	1.03E-03	1.03E-03	1.03E-03	0.00E+00	0.00E+00	0.00E+00	0.00E+00	6.19E-04	6.19E-04	8.41E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
N2O Emission Rate		tons/event	1.24E-04	1.24E-04	2.05E-04	2.05E-04	2.05E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00	1.24E-04	1.24E-04	1.68E-04	0.00E+00	0.00E+00	0.00E+00	0.00E+00

* VOC includes Propane

Total Annual Emissions		GWP	CO2e (tpy)
CO2 Emissions (tpy)	38.66	1	38.66
CH4 Emissions (tpy)	0.00	21	0.03
N2O Emissions (tpy)	0.00	310	0.10
			38.80

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.

Equations Used:

Standing Idle - Drain Dry (Eqn 2-22)

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

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

Forced Ventilation

Forced ventilation emissions are controlled.

Losses = $0.0000414 \times U_S^{0.78} \times VP \times MW^{0.67} \times A_P^{0.94}\ (1 - DRE)$

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

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

Appendix B

RACT/BACT/LAER Clearinghouse Search Tables

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 Heate	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 Heate	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 and 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-M	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 natural 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 natural 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	