PREVENTION OF SIGNIFICANT DETERIORATION GREENHOUSE GAS PERMIT APPLICATION FOR ADDED COMBUSTION SOURCES

SUBMITTED TO:

U.S. ENVIRONMENTAL PROTECTION AGENCY, REGION VI
MULTIMEDIA PLANNING AND PERMITTING DIVISION
FOUNTAIN PLACE 12TH FLOOR, SUITE 1200
1445 ROSS AVENUE
DALLAS, TEXAS 75202-2733

SUBMITTED BY:

PL PROPYLENE LLC
HOUSTON, TEXAS 77017

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
11200 WESTHEIMER ROAD, SUITE 600
HOUSTON, TX 77042

ZEPHYR PROJECT 011377

DECEMBER 2012

(ORIGINAL SUBMITTAL FEBRUARY 2012)

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Air Quality Impact Analysis
Biological Assessment
Cultural Resources Review
Essential Fish Habitat Assessment

1.0 INTRODUCTION

PL Propylene LLC (PLP) is located at 9822 La Porte Freeway, Houston, Texas 77017. In 2008, Texas Commission on Environmental Quality (TCEQ) New Source Review (NSR) Permit No. 18999 was amended to authorize the modification of facilities to produce propylene using a licensed propane dehydrogenation technology. The modification was completed in 2010 and the plant was restarted in 2011. This permit application is required authorize the emissions of Greenhouse Gases (GHG) resulting from the installation of additional new combustion units, new heaters, a new waste heat boiler, a new flare, and natural gas piping associated with a proposed plant modification. Also associated with this modification, a TCEQ NSR permit amendment application to authorize the non-GHG emissions has been submitted to the TCEQ.

On June 3, 2010, the Environmental Protection Agency (EPA) published final rules for permitting sources of GHG under the Prevention of Significant Deterioration (PSD) and Title V air permitting programs known as the GHG Tailoring Rule.[1] After July 1, 2011, new sources having the potential to emit more than 100,000 tons per year (tpy) of carbon dioxide equivalents (CO_2e) and modifications increasing GHG emissions more than 75,000 tpy on a CO_2e basis at existing major sources are subject to GHG PSD review, regardless of whether PSD is triggered for the other criteria pollutants.

On December 9, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required State Implementation Plan (SIP) revision for GHG permitting and it is approved by EPA.[2] This project will consist of the addition of six new proprietary process combustion units, a charge gas heater, a regeneration air heater, a waste heat boiler, a flare, and associated natural gas piping. A PSD review for GHG regulated pollutants is trigged because the operation of these new sources will increase GHG emissions by more than 100,000 tpy.

This application was originally submitted in February 2012. This revision addresses the deficiencies noted by EPA during their completeness determination and subsequent review, and consolidates and supersedes all prior permit application information.

The following additional information has been provided under separate correspondence.

- TCEQ NSR Permit Application for non-GHG pollutants
- Air Quality Impact Analysis
- Biological Assessment
- Cultural Resources Review
- Essential Fish Habitat Assessment

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[1] 75 FR 31514 (June 3, 2010).

[2] 75 FR 81874 (Dec. 9, 2010).

Texas Commission on Environmental Quality
Form PI-1 General Application for Air Preconstruction Permit and Amendment

Important Note: The agency **requires** that a Core Data Form be submitted on all incoming applications unless a Regulated Entity and Customer Reference Number have been issued *and* no core data information has changed. For more information regarding the Core Data Form, call (512) 239-5175 or go to www.tceq.texas.gov/permitting/central_registry/guidance.html.

I. Applicant Information		
A. Company or Other Legal Name: PL Propylene LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*): 800769962		
B. Company Official Contact Name: Mr. John Parkinson		
Title: VP Manufacturing		
Mailing Address: 9822 La Porte Freeway		
City: Houston	State: Texas	ZIP Code: 77017
Telephone No.: 713-740-3915	Fax No.: 713-740-3999	E-mail Address: jparkinson@petrologistics.com
C. Technical Contact Name: Mr. Vance Darr		
Title: Environmental Manager		
Company Name: PL Propylene LLC		
Mailing Address: 9822 La Porte Freeway		
City: Houston	State: Texas	ZIP Code: 77017
Telephone No.: 713-740-3925	Fax No.: 713-740-3999	E-mail Address: vdarr@petrologistics.com
D. Site Name: PL Propylene LLC		
E. Area Name/Type of Facility: Propylene Manufacturing Unit	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Industrial Organic Chemicals		
Principal Standard Industrial Classification Code (SIC): 2869		
Principal North American Industry Classification System (NAICS): 32511		
G. Projected Start of Construction Date: 04/01/2013		
Projected Start of Operation Date: 10/01/2014		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 9822 La Porte Freeway		
City/Town: Houston	County: Texas	ZIP Code: 77017
Latitude (nearest second): 29deg 42min 17sec	Longitude (nearest second): 95deg15min 2sec	

2.0 PROJECT SCOPE

2.1 INTRODUCTION

The process manufactures commercial quantities of chemical and polymer grade propyleneby dehydrogenation of propane over a fixed-bed catalyst. The reactor effluent is fed to compression and recovery systems where the products are recovered and unconverted propane is recycled to the reaction system. A modification is proposed to produce an additional 1.6 billion pounds a year of product propylene. Co-product streams of H_2, C4's, C5's, and Quench Oil, accounting for 2.0% of total production, are also produced.

PLP is proposing the following facility modifications:

1) Six new proprietary combustion units (FINs GT6, GT7, GT8, GT9, GT10, and GT11)
2) New charge gas heater (FIN RCH2)
3) Regeneration air heater (FIN RAH2)
4) New waste heat boiler (FIN WHB2)
5) New flare (FIN FLARE2)
6) Natural gas piping fugitives (FIN PLANT2)

2.2 PROPRIETARY PROCESS COMBUSTION UNITS

The process combustion units (GT6 through GT11) will burn pipeline quality natural gas to produce the hot gas needed to regenerate the catalyst in the dehydrogenation reactors. The plant catalyst regeneration system consists of combustion units and electric blowers whose exhausts are manifolded together. The gas passes through a direct-fired air heater to raise the exhaust gases to a temperature sufficient to regenerate the dehydrogenation catalyst. The hot gases leaving the regeneration step then pass through a waste heat boiler which uses the heat content of the gases to generate steam before being vented to the atmosphere. Supplemental fuel firing is used in the waste heat boiler to get the steam to the proper pressure and temperature for use at the PLP site.

During normal regeneration operations, the combustion units vent through the waste heat boiler (WHB2). During routine maintenance, startup, and shutdown (MSS) operations, the combustion units will vent directly to the atmosphere, at the same rate as normal operations, to prevent an unsafe operating condition. A process flow diagram showing routine and MSS operations is included as Figure 2-1

2.3 CHARGE GAS HEATER

The propane feed to the dehydrogenation reactors first passes through a charge gas heater (RCH2) fired with a combination of natural gas and process fuel gas to increase temperature of the feed to enable the dehydrogenation reaction to occur. The combustion gases from the heater pass through a selective catalytic reduction (SCR) system to reduce NO_X emissions.

2.4 DIRECT- FIRED AIR HEATER

Exhaust gases from the proprietary combustion units pass through a direct-fired regeneration air heater (RAH2) to achieve the necessary regeneration temperature. This heater is fired with natural gas and process fuel gas.

2.5 WASTE HEAT BOILER

The waste heat boiler (WHB2) receives the exhaust gases from the reactor regeneration and uses the heat of the gases to produce steam. Supplemental fuel (natural gas and process fuel gas) is used to get the steam to the proper pressure and temperature for use in plant operations. The combustion gases leaving the WHB2 pass through a catalytic oxidation (CATOX) unit to control CO and VOC emissions and a SCR system to control NO_X emissions.

2.6 FLARE

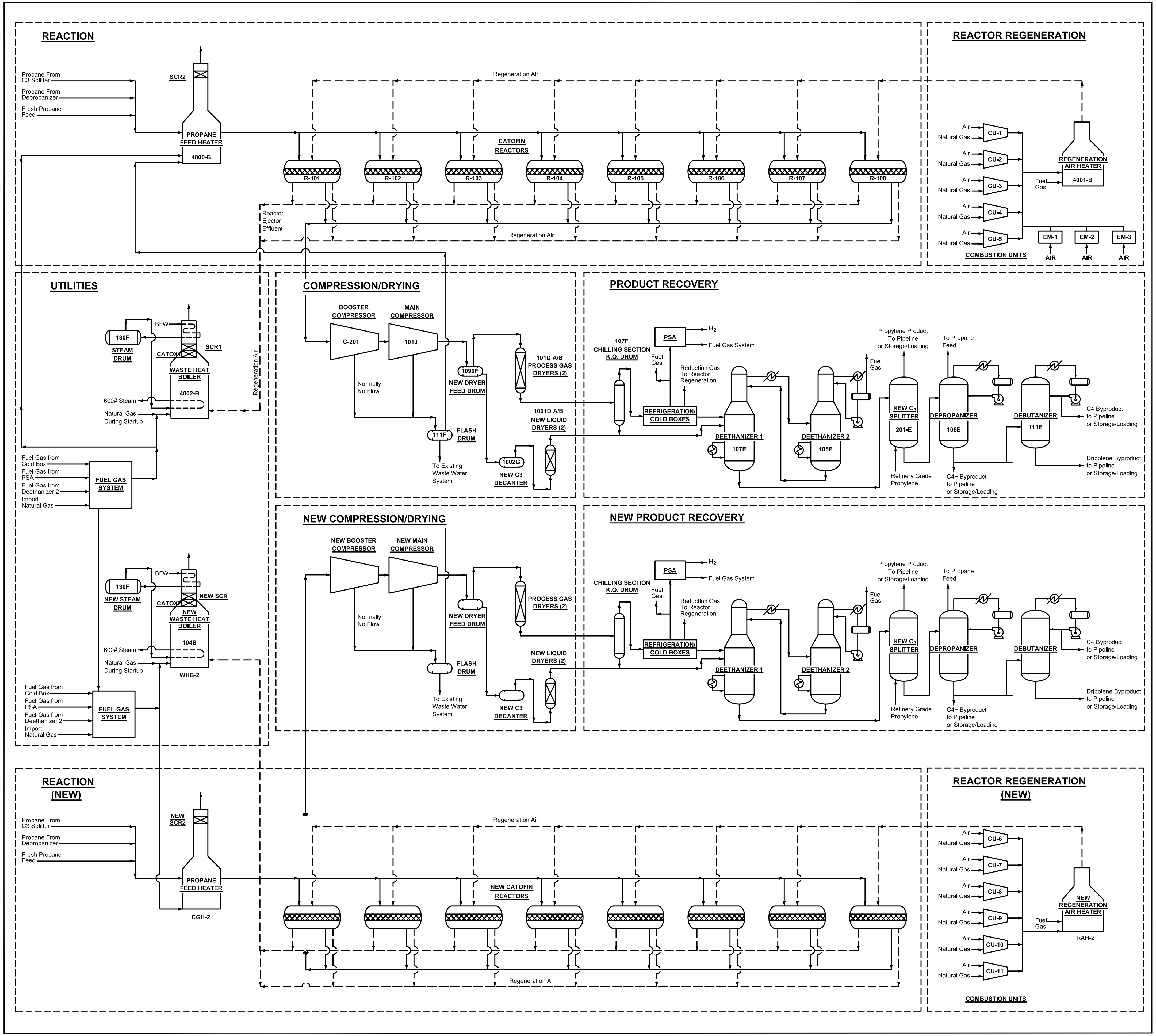
A new ground level process/emergency flare (FLARE2) will be added to safely combust process vent streams during maintenance, startup, and shutdown operations.

2.7 NATURAL GAS PIPING

Natural gas is delivered to the site via pipeline. The gas will be metered and piped to the new combustion units being installed as part of this project. Fugitive emissions from the natural gas piping components (FIN NG-FUG2) associated with these units will include emissions of methane (CH_4) and carbon dioxide (CO_2).

2.8 ELECTRICAL EQUIPMENT INSULATED WITH SULFUR HEXAFLUORIDE (SF6)

The generator circuit breaker associated with the proposed unit will be insulated with SF6, which is a colorless, odorless, non-flammable, and non-toxic synthetic gas. It is a fluorinated compound that has an extremely stable molecular structure. The unique chemical properties of SF6 make it an efficient electrical insulator. The gas is used for electrical insulation, arc quenching, and current interruption in high-voltage electrical equipment. SF6 is only used in sealed and safe systems which under normal circumstances do not leak gas.



Original Drawing Source: Supplied by Client

zephyr

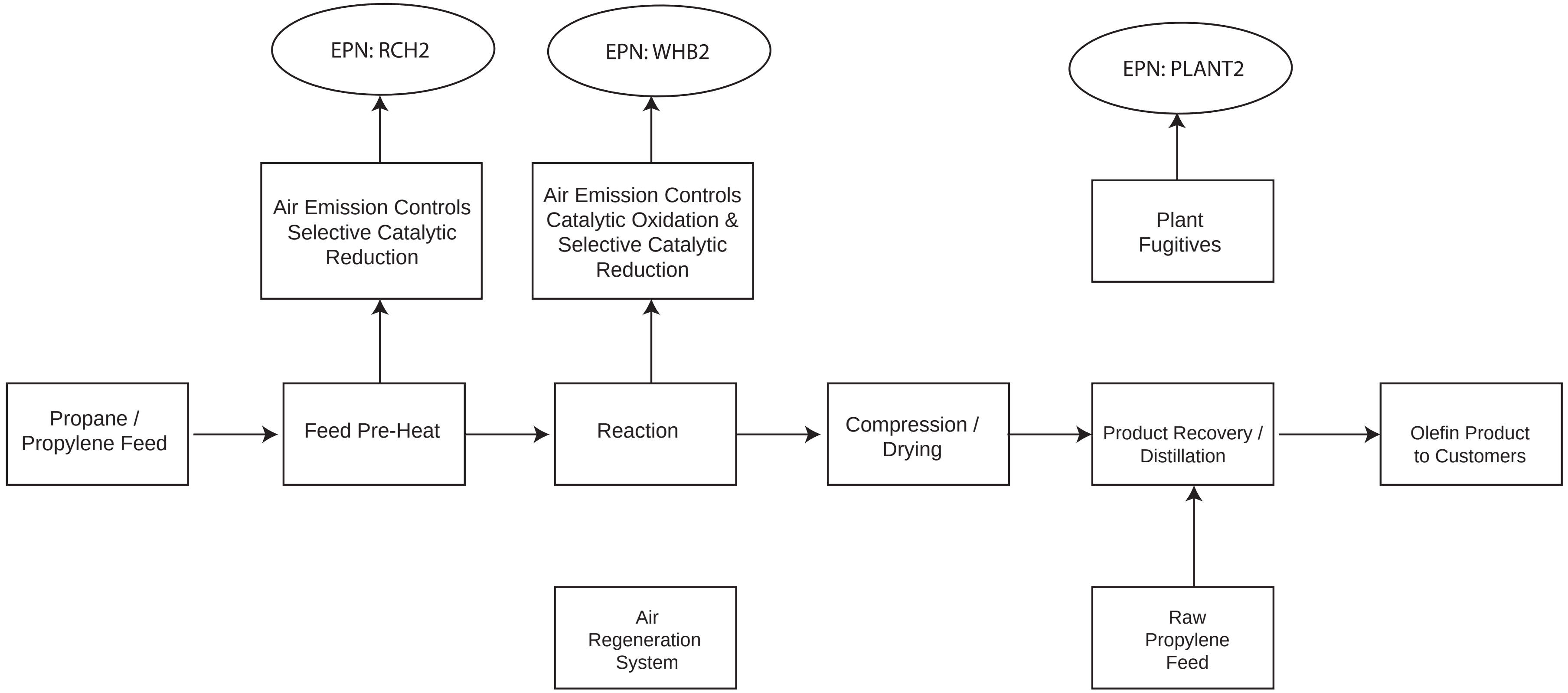
PROCESS FLOW DIAGRAM
FIGURE F-1

Houston Olefins Plant
PL Propylene LLC
Houston, Texas

Filename: K:\PL Propylene\011377 2014 Expansion

Designed By:	Reviewed By:	Project No.:	Created:	Revised:
R. von Czoernig	Ed. Fiesinger	011377	1-6-12	5-31-12

EPN= Emissions Point Number



* Includes the Dryer Regenerator Heater,
and the Spare Regenerator Heater

FIGURE 1-1: PROCESS FLOW DIAGRAM

HOUSTON OLEFINS PLANT
PL PROPYLENE LLC

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Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	E. Fessinger	11377	05/24/2012

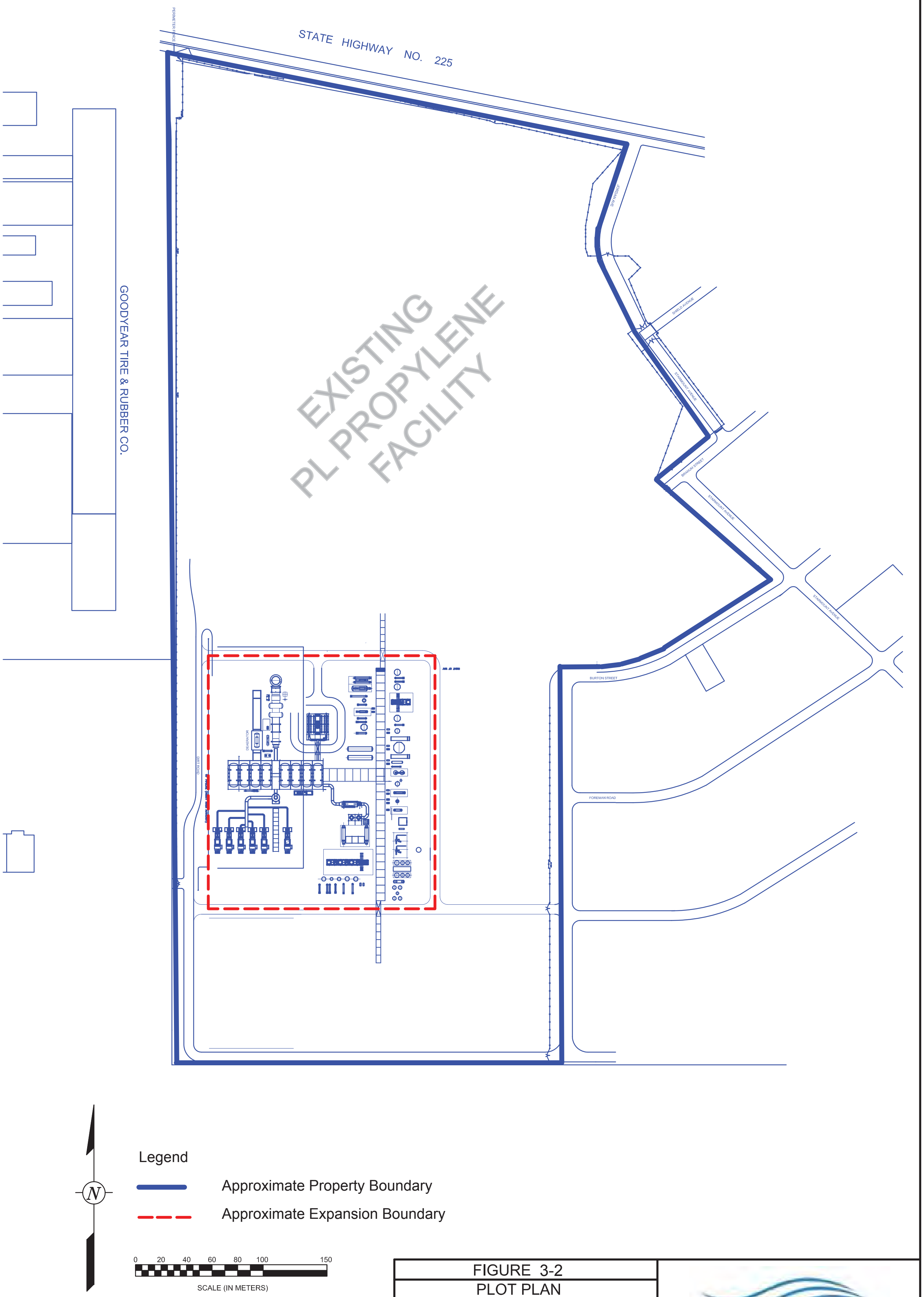

FIGURE 3-2

PLOT PLAN

PL PROPYLENE LLC

File Name: H:\PL Propylene\Jens Graphics for 11377 BA

Designed By:	Checked By:	Project No.:	Date:
RvC	S. McVey	11377	09/10/2012

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Datum: GCS NAD 1983, UTM Zone 15
Map Sources: ESRI Bing Hybrid
Basemap & Streets Basemap;
PL Propylene, LLC

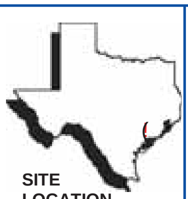

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FIGURE 4-1:
ACTION AREA

PL Propylene, LLC
Harris County, Texas

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Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	R. Fisher	011377	09/14/2012

3.0 EMISSION CALCULATIONS

The emissions calculation methodologies used to determine the proposed emissions associated with this project are described in the following sections. A summary of the calculated GHG emissions is presented in Appendix A-1. Criteria pollutant emissions and stack parameters for the proposed new GHG emission sources are shown in Table 1(a) following this section.

3.1 GHG EMISSIONS FROM COMBUSTION SOURCES

The GHG emission for the combustion sources are calculated in accordance with the procedures specified in the Mandatory Greenhouse Reporting Rules, Subpart C – General Stationary Fuel Combustion Sources (Appendix A-2).[3] The permitted CO_2 emissions are calculated using equation C-1. The annual CO2 emissions are calculated using equations C-2 and C-3 based on plant operating conditions.

$CO_2 = (1 \times 10^{-3})$*Fuel*HHV*EF (Equation C-1)

Where:

CO_2 = Annual CO_2 mass emissions for a specific fuel type (metric tons).

0.001= Conversion factor from kg to metric tons.

Fuel = Mass or volume of the natural gas combusted during the year, from company records as defined in §98.6 (express volume in standard cubic foot for gaseous fuel).

HHV = Default high heat value of the natural gas from Table C-1 (MMBTU per volume).

EF = Fuel-specific default CO_2 emission factor for natural gas from Table C-1 (kg CO_2/MMBTU).

Emissions of CH_4 and nitrous oxide (N_2O) are calculated using the emission factors (kg/MMBTU) for natural gas combustion from Table C-2 of the Mandatory Greenhouse Gas Reporting Rules.[4] The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

The use of process fuel gas will affect the high heat value of the combined process fuel and natural gas stream. However, because the quality and quantity of process fuel gas is variable, the GHG emission calculations are based on natural gas only and no credit has been taken for the use of the lower CO_2 potential process fuel gas.

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[3] 40 CFR 98, Subpart C – General Stationary Fuel Combustion Sources

[4] *Default CH_4 and N_2O Emission Factors for Various Types of Fuel*, 40 CFR 98, Subpart C, Table C-2

3.2 GHG EMISSIONS FROM FLARE

The flare is will combust primarily propylene and propane process gasses from maintenance startup and shutdown operations. During routine operation minimal process sweeps are routed through the flare header to maintain safe operating conditions. GHG emissions for the flare are calculated in accordance with the procedures specified in the Mandatory Greenhouse Reporting Rules, Subpart Y – Petroleum Refineries, using equation Y-2 for CO_2, Y-4 for CH_4, and Y-5 for N_2O: A 98% destruction efficiency for VOC was applied according to EPA documents.[5]

CO_2 = Flare Combustion Efficiency* (1×10^{-3})*Flare Gas Mass Flow*Molar Volume Conversion Factor/Flare Gas Molecular Weight

Volume Flare Gas (MMSCF) = 0.000001*Flare Gas Mass Flow*Molar Volume Conversion Factor/Flare Gas Molecular Weight

The proposed new flare is a multi-use flare that will be used to control emissions from routine processes, maintenance, startup, and shutdown activities (MSS), and emergency releases.

3.3 GHG EMISSIONS FROM NATURAL GAS PIPING FUGITIVES

GHG emission calculations for natural gas piping component fugitive emissions are based on emission factors from Table W-1A (Western U.S.) of the Mandatory Greenhouse Gas Reporting Rules.[6] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[7]

3.4 GHG EMISSIONS FROM ELECTRICAL EQUIPMENT INSULATED WITH SF6

The capacity of the generator circuit breaker associated with the proposed unit will be approximately 72 lb. SF6 emissions from the new generator circuit breaker associated with the proposed unit are calculated using a predicted SF6 annual leak rate of 0.5% by weight. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

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[5] AP_42, Chapter 13.5, for flares meeting 40 CFR §60.18

[6] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production,* 40 CFR Part 98, Subpart W, Table W-1A

[7] *Global Warming Potentials,* 40 CFR. Part 98, Subpart A, Table A-1

3.5 GHG EMISSION POTENTIAL FROM PROCESS FUEL GAS

To optimize energy utilization in the process, off-gas resulting from the dehydrogenation process and product recovery steps is used to supplement natural gas in RCH2, RAH2, and WHB2. This quantity of process fuel gas varies and is dependent on process feedstock quality, operating conditions and the age of the dehydrogenation catalyst. The fuel gas is typically composed of the following constituents:

1) C2's – 5% – 15%
2) Hydrogen – 5% - 25%
3) Methane – 15% - 30%
4) C3's – 15% - 75%
5) C4s - < 1%
6) CO and CO_2 – 5% - 15%

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) Emission Point Summary

Date: 12/10/12	**Permit No.:** 18999	**Regulated Entity No.:** RN102576063
Area Name: PL Propylene LLC		**Customer Reference No.:** CN603337676

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA

1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) PPH**	**(B) TPY**
GT6	GT6/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03
GT7	GT7/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03
GT8	GT8/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03
GT9	GT9/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) Emission Point Summary

Date:	12/10/12	**Permit No.:**	18999	**Regulated Entity No.:**	RN102576063
Area Name:	**PL Propylene LLC**			**Customer Reference No.:**	CN603337676

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) PPH**	**(B) TPY**
GT10	GT11/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03
GT11	GT11/WHB2 MSS	Gas Turbine MSS	NOx	70.00	2.16
			CO	30.00	0.72
			VOC	0.42	0.06
			SO2	0.68	0.02
			PM	1.32	0.05
			PM10	1.32	0.05
			PM2.5	0.94	0.03
FLARE2	FLARE2	Flare (Routine)	NOx	28.09	12.72
			CO	143.13	64.80
			SO2	9.96	0.18
			Ethylene	3.60	1.93
			Propylene	36.00	9.64
			Butene	10.80	5.78
			Butadiene	7.20	0.96
			Benzene	7.20	0.96
			VOC	88.20	31.80
			H2S	0.11	0.01
FLARE2	FLARE2MSS	Flare (MSS)	NOx	86.34	0.94
			CO	623.61	6.78
			SO2	31.72	0.34
			Ethylene	85.94	0.46
			Propylene	674.00	2.28

EPN = Emission Point Number

FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) Emission Point Summary

Date: 12/10/12	**Permit No.:** 18999	**Regulated Entity No.:**	RN102576063
Area Name: PL Propylene LLC		**Customer Reference No.:**	CN603337676

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA

1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) PPH**	**(B) TPY**
			Butene	67.40	0.73
			Butadiene	55.61	0.09
			Benzene	42.13	0.09
			VOC	925.07	5.11
			H2S	0.10	0.01
RCH2	RCH2	Charge Gas Heater	NOx	2.98	12.95
			CO	2.39	10.38
			Ethylene	0.28	1.24
			Propylene	0.07	0.31
			VOC	0.43	1.85
			SO2	3.73	16.18
			PM	1.86	8.09
			PM10	1.40	6.07
			PM2.5	1.05	4.55
			NH3	1.82	7.89
			H2S	<0.01	<0.01
WHB2	WHB2	Waste Heat Boiler	NOx	27.08	104.61
			CO	22.99	87.23
			Ethylene	0.19	0.86
			Propylene	0.15	0.49
			VOC	1.24	5.32
			SO2	10.01	43.61
			PM	1.50	6.55
			PM10	1.50	6.55
			PM2.5	1.08	4.81
			NH3	25.53	78.26
			H2S	0.01	0.01
PLANT2	PLANT2	LDAR Fugitives	VOC	4.79	19.63
			Ethylene	0.24	0.98

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) Emission Point Summary

Date:	**12/10/12**	**Permit No.:**	**18999**	**Regulated Entity No.:**	RN102576063
Area Name:	**PL Propylene LLC**			**Customer Reference No.:**	CN603337676

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) PPH**	**(B) TPY**
			Propylene	2.39	9.82
			Butene	0.05	0.20
			Butadiene	0.01	0.02
			Benzene	0.01	0.02

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY
Table 1(a) Emission Point Summary

12/10/12	**Permit No. 18999**	**Regulated Entity No.:**	**RN102576063**
Area Name: PL Propylene LLC		**Customer Reference No.:**	**CN603337676**

Review of applications and issuance of permits will be expedited by supplying all necessary information requested on this Table.

AIR CONTAMINANT DATA			**EMISSION POINT DISCHARGE PARAMETERS**										
1. Emission Point			**4. UTM Coordinates of Emission Point**			**Source**							
						5. Building Height (ft.)	**6. Height Above Ground (ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diameter (ft.)**	**(B) Velocity (fps)**	**(C) Temperature (°F)**	**(A) Length (ft.)**	**(B) Width (ft.)**	**(C) Axis Degrees**
GT6	GT6/WHB2 MSS	Gas Turbine MSS	15	282147	3287764		70	2.5	250.0	1000			
GT7	GT7/WHB2 MSS	Gas Turbine MSS	15	282156	3287764		70	2.5	250.0	1000			
GT8	GT8/WHB2 MSS	Gas Turbine MSS	15	282165	3287764		70	2.5	250.0	1000			
GT9	GT9/WHB2 MSS	Gas Turbine MSS	15	282174	3287764		70	2.5	250.0	1000			
GT10	GT11/WHB2 MSS	Gas Turbine MSS	15	282183	3287764		70	2.5	250.0	1000			
GT11	GT11/WHB2 MSS	Gas Turbine MSS	15	282202	3287764		70	2.5	250.0	1000			
FLARE2	FLARE2	Flare (Routine)	15	282172	3287658		10	225.7	0.07	1500.0			
FLARE2	FLARE2MSS	Flare (MSS)	15	282182	3287878		10	225.7	0.07	1500.0			
RCH2	RCH2	Charge Gas Heater	15	282225	3287866		132	8.0	50.0	400.0			
WHB2	WHB2	Waste Heat Boiler	15	282193	3287895		150	20.0	48.7	300.0			
PLANT2	PLANT2	LDAR Fugitives	15	282140	3287716		3			77	650	585	0

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ - 10153 (Revised 04/08) Table 1(a)
This form is for use by sources subject to air quality permit requirements and
may be revised periodically. (APDG 5178 v5)

4.0 PREVENTION OF SIGNIFICANT DETERIORATION

In the EPA guidance document *PSD and Title V Permitting Guidance for Greenhouse Gases,* the following PSD Applicability Test was provided for Step 2 of the PSD Tailoring Rule for new sources:

EPA Tailoring Rule Step 2 - PSD Applicability Test for GHGs

PSD applies to the GHG emissions from a proposed new source if ***either*** of the following is true:

- PSD for GHG would be required under Tailoring Rule Step 1, ***or***
- The potential emissions of GHG from the new source would be equal to or greater than 100,000 tpy CO_2e basis ***and*** equal to or greater than the applicable major source threshold (i.e., 100 or 250 tpy, depending on the source category) on a mass basis for GHG.

The emissions increase of GHG from either case is greater than 100,000 tpy of CO_2e and greater than 100 or 250 tpy on a mass basis, thus triggering PSD for GHG emissions.

5.0 BEST AVAILABLE CONTROL TECHNOLOGY (BACT)

The PSD rules define BACT as:

Best available control technology means an emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under [the] Act which would be emitted from any proposed major stationary source or major modification which the Administrator, on a case-by-case basis, taking into account energy, environmental, and economic impacts and other costs, determines is achievable for such source or modification through application of production processes or available methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61. If the Administrator determines that technological or economic limitations on the application of measurement methodology to a particular emissions unit would make the imposition of an emissions standard infeasible, a design, equipment, work practice, operational standard, or combination thereof, may be prescribed instead to satisfy the requirement for the application of best available control technology. Such standard shall, to the degree possible, set forth the emissions reduction achievable by implementation of such design, equipment, work practice or operation, and shall provide for compliance by means which achieve equivalent results.[8]

In the EPA guidance document titled *PSD and Title V Permitting Guidance for Greenhouse Gases*, EPA recommended the use of the Agency's five-step "top-down" BACT process to determine BACT for GHGs.[9] In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT.

EPA has broken down this analytical process into the following steps:

1) Identify all available control technologies.
2) Eliminate technically infeasible options.
3) Rank remaining control technologies.
4) Evaluate most effective controls and document results.
5) Select the BACT.

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[8] 40 C.F.R. § 52.21(b) (12)

[9] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (Nov. 2010).

The following guidance documents and data sources were used in this study to determine the acceptable control technologies as part of step 1 of the 5-step EPA BACT review process:

1) EPA RACT/BACT/LAER Clearinghouse[10]

2) *PSD and Title V Permitting Guidance for Greenhouse Gases*[11]

3) *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers* [12]

4) *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from The petroleum Refining Industry* [13]

5) *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR® Guide for Energy and Plant Managers* [14]

This project contains the following sources of GHG emissions:

1) One charge gas heater (FIN RCH2) fired with natural gas and process fuel gas to preheat the raw materials (fresh and recycled propane) before they enter the dehydrogenation rectors.

2) Six proprietary natural gas-fired combustion units (FINs GT6 to GT11) to generate a sufficient quantity of heated air necessary for the regeneration of the dehydrogenation reactors' catalyst.

3) One direct fired regeneration air heater (FIN RAH2) fired with natural gas to boost the exhaust gases from the proprietary combustion units (GT6 – GT11) up to the proper process temperature for regeneration of the catalyst in the reactors.

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[10] (http://cfpub.epa.gov/RBLC/index.cfm?action=Home.Home&lang=en)

[11] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC; March 2011 (http://www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf

[12] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC; October 2010 (http://www.epa.gov/nsr/ghgdocs/iciboilers.pdf

[13] U.S. EPA, Office of Air and Radiation, Office of Air Quality Planning and Standards, (Research Triangle Park, NC; October 2010 (http://www.epa.gov/nsr/ghgdocs/refineries.pdf

[14] Environmental Energy Technologies Division, University of California, sponsored by USEPA, June 2008 http://www.energystar.gov/ia/business/industry/Petrochemical_Industry.pdf

4) One waste heat boiler (FIN WHB2) fired with supplemental natural gas and process fuel gas to recover heat from the gases leaving the regeneration step by generating steam for use elsewhere at the site.

5) One flare (FIN FLARE2) fired with natural gas to safely combust routine process vent streams and to combust flammable gases during emergencies and periods of MSS activities.

6) Piping fugitives (PLANT2) associated with the natural gas lines used to fuel the various combustion units (RCH2, RAH2, FLARE2, and WHB2).

Because the charge gas heater and waste heat boiler are each separate emission units whose combustion emissions can be controlled, post-combustion controls will be considered as a potential control technology for each. Since emissions from the proprietary combustion units and regeneration air heater go directly to the waste heat boiler and are not vented to the atmosphere, post-combustion controls will not be considered as a potential control technology. Because flares control VOCs by combusting the gases at the flare tip, recovery of the products of combustion is not achievable, thus eliminating carbon capture and storage as a potential control technology.

The 5-step BACT analysis for post-combustion controls is addressed separately at the end of this section.

The results of a search of the RACT/BACT/LAER Clearinghouse for what is BACT for GHG are shown on Table 5-1. A cost analysis for post-combustion controls (carbon capture and storage) is presented in Table 5-2. A proposed monitoring schedule for each system addressed in this BACT review is shown on Table 5-3.

5.1 NATURAL GAS-FIRED PROCESS COMBUSTION UNITS (GT6 TO GT11)

The proprietary natural gas-fired process combustion units are used to generate a sufficient quantity of hot air for the regeneration (decoking) of the dehydrogenation catalyst in the fixed-bed reactors. As such these units are designed to operate at 1,000% excess air. These units only vent to the atmosphere during periods of maintenance, startup, and shutdown (MSS). Thus they are separate emission points for NSR purposes, but since the duration of atmospheric venting is short (a period of minutes), post combustion controls for any pollutant is not achievable. Each unit is rated at 200 MMBTU/HR heat input (natural gas firing).

5.1.1 Step 1 – Identification of Potential Control Technologies

Inherently Lower-Emitting Processes/Practices/Designs

PL Propylene (PLP) performed a search of the EPA’s RACT/BACT/LAER Clearinghouse for natural gas fired combustion generators and found no entries which address BACT for GHG emissions. A literature search showed that, a GHG BACT analysis was performed by the Russell City Energy Center for a 612 MW natural gas fired combined cycle power plant to be located in Hayward, California which is indicative of what BACT is for the Combustion Units in this project. That analysis determined that BACT for GHG emissions was maintenance of the high energy efficiency that is inherent with natural gas fired combined cycle power plants.

A summary of available, lower greenhouse gas emitting processes, practices, and designs for combustion units is presented below.

Combustion Unit Design

CO_2 is a product of combustion of fuel containing carbon, which is inherent in any combustion technology using fossil fuel. It is not possible to reduce the amount of CO_2 generated from combustion, as CO_2 is the essential product of the chemical reaction between the fuel and the oxygen in which it burns, not a byproduct caused by imperfect combustion. As such, there is no technology available that can effectively reduce CO_2 generation by adjusting the conditions in which combustion takes place.

The only effective means to reduce the amount of CO_2 generated by a fuel-burning combustion unit is to reduce the amount of fuel needed to meet the units heated gas output needs. This result is obtained by using the most efficient generating technologies available, so that as much of the energy content of the fuel as possible goes into generating the heated gases.

In addition to the high-efficiency primary components of the generator, there are a number of other design features employed within the generator that can improve the overall efficiency of the machine. These additional features include those summarized below.

Periodic Tuning

Modern combustion units have regularly scheduled maintenance programs. These maintenance programs are important for the reliable operation of the unit, as well as to maintain optimal efficiency. As the combustion unit is operated, the unit experiences degradation and loss in performance. The combustion unit maintenance program helps restore the recoverable lost performance. The maintenance program schedule is determined by the number of hours of operation. There are three basic maintenance levels, commonly referred to as combustion inspections, hot gas path inspections, and major overhauls. Combustion inspections are the most frequent of the maintenance cycles. As part of this maintenance activity, the combustors are tuned to restore highly efficient low-emission operation.

Reduction in Heat Loss

Modern combustion units have high operating temperatures. The high operating temperatures are a result of the heat of compression in the compressor along with the fuel combustion in the burners. To minimize heat loss from the combustion unit and protect the personnel and equipment around the machine, insulation blankets are applied to the combustion unit casing. These blankets minimize the heat loss through the combustion unit shell and help improve the overall efficiency of the machine.

Instrumentation and Controls

Modern combustion units have sophisticated instrumentation and controls to automatically control the operation of the combustion unit. The control system is a digital-type and is supplied with the combustion unit. The distributed control system (DCS) controls all aspects of the unit's operation, including the fuel feed and burner operations, to achieve efficient low-NO_X combustion. The control system monitors the operation of the unit and modulates the fuel flow and unit operation to achieve optimal high-efficiency low-emission performance for full-load and part-load conditions.

5.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

An improved design combustion unit is presently commercially available from the manufacturer. This makes this control option technically feasible.

Recommended maintenance and operating procedures are available from the manufacturer.

5.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

As documented elsewhere in this section, implementation of CCS technology is currently infeasible, leaving energy efficiency measures as the only technically feasible emission control options. As all of the energy efficiency related processes, practices, and designs discussed are being proposed for this project, a ranking of the control technologies is not necessary for this application.

According to the manufacture of these units, they have power increase of 7.5 to 9.0% at base load and a 4.4% higher thermal efficiency than comparable older units which significantly reduces CO and CO_2 emissions when operating at the enhanced or current base rating. As-built technology improvements are more effective than procedural controls since they are inherently built into the system.

These units will be operated according to their manufacturer's recommended operation and maintenance procedures regarding preventive maintenance (PM) schedules, what to monitor, and at what frequency to assure that the equipment performs as designed.

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

Because the CCS add-on control option discussed elsewhere in this section was determined to be technically infeasible, an examination of the energy, environmental, and economic impacts of that option is not necessary for this application. However, at the request of EPA Region 6, PLP is included estimated costs for implementation of CCS.

Improved unit design is the most effective control technology since it is a one-time up- front cost and doesn't rely on personnel following the manufacturer's recommended maintenance and operation procedures.

Operating the units as recommended by the manufacturer can be an effective technology, but only if maintenance and operations personnel follow the manufacturers recommended procedures.

5.1.5 Step 5 – Selection of BACT

BACT for these combustion units consists of use of the latest technical design for the units coupled with proper maintenance to keep the units running at their peak capability of 117.3 lb CO_2/MMBTU heat input when burning natural gas. Such efficient operation will minimize CO_2 formation in the combustion process. Each unit operates at greater than 1,100°F and has a proprietary fuel gas and burner management system to monitor the combustion efficiency of the equipment. When the temperature measured across the burners differs by more than a set temperature of 158°F, an alarm is activated and the cause of the alarm is investigated and resolved by the operating personnel.

This state-of-the-art design and other waste heat recovery operations produces propylene at an energy usage of 8,000 BTU/LB of product versus conventional technology energy usage of 12,000 BTU/LB of product. Periodic preventive maintenance and routine monitoring of operating variables will assure that the units operate as designed. The manufacturer recommends every 4,000 and 21,000 operating hours (base load) that a detailed visual inspection be conducted to check for external leakage, drain systems pluggage, air intake system, and exhaust unit.

The following additional BACT practices are proposed for GT6 – GT11:

- Determine net CO_2 emissions from the downstream boiler stack (WHB2) based on continuous monitoring of CO_2 emissions. Alternatively, metered fuel consumption and standard emission factors and/or fuel composition and mass balance can be used.

- Perform periodic tune-ups of duct burners.

- Calibrate and perform preventive maintenance on the fuel flow meters.

5.2 GAS FIRED HEATER (RAH2)

The Regeneration Air Heater (RAH2) takes the exhaust gases from the proprietary combustion units and heats these gases about 60 °F, thereby boosting the gases to the temperature necessary for regenerating the catalyst in the fixed-bed reactors. It is a direct-fired air heater equipped with a low NO_X duct burner, with the combustion products mixing with the gas from the combustion units before going to the reactors. The air heater and burner are a ZEECO or equivalent design. It is a forced draft heater and the exit temperature is continuously monitored (> 1,100 °F) fired with natural gas and process fuel gas.

5.2.1 Step 1 - Identification of Potential Control Technologies

The applicable technologies for controlling GHG emissions from the regeneration air heater duct burner include the following:

- Periodic Burner Tune-up - The duct burners and heat recovery steam generators (HRSG) are tuned periodically to maintain optimal thermal efficiency.

- Oxygen Trim Control - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.

- Use of Hydrogen as a Fuel - Partial replacement of natural gas (methane) with hydrogen (produced as a product in the reaction process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.

5.2.2 Step 2 – Elimination of Technically infeasible Alternatives

Oxygen trim control, feasible for stand-alone boilers, is not applicable to duct burners. Therefore, this option was eliminated on the basis of technical infeasibility. All remaining options identified in Step 1 are considered technically feasible.

The remaining options, periodic burner tune-up and use of hydrogen as a fuel, are both technically feasible.

5.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. The sale of hydrogen product however is an integral part of the business model of the plant. The substitution of hydrogen also causes an associated increase in NOx emissions because of higher flame temperature and reduced flame stability in the burner. The effectiveness of substituting hydrogen is high, but for the variables listed the effectiveness of this option is reduced. It is anticipated that there will be periods when hydrogen product cannot be sold. During those periods, using hydrogen to the maximum extent possible as a fuel in the burners of RAH2 in place of natural gas reduces GHG emissions.

Currently, periodic tune-ups of the duct burners are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

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

The business plan calls for sale of the hydrogen stream, and market conditions will dictate which feeds are used, and the resulting quantity of hydrogen product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice.

Periodic tune-ups of the duct burners and preventive maintenance and calibration of the fuel flow meters is performed as needed at the plant.

5.2.5 Step 5 – Selection of BACT

The following additional BACT practices are proposed for RAH2:

- Determine net CO_2 emissions from the downstream boiler stack (WHB2) based on continuous monitoring of CO_2 emissions. Alternatively, metered fuel consumption and standard emission factors and/or fuel composition and mass balance can be used.
- Perform periodic tune-ups of duct burners.
- Calibrate and perform preventive maintenance on the fuel flow meters.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the duct burner or other existing combustion units at the site.

5.3 CHARGE GAS HEATER (RCH2)

The raw material propane and recycled propane and propylene are heated in the Charge Gas Heater (RCH2) prior to entering the Catofin® reactors. The combustion flue gases from the heater pass through a selective catalytic reduction (SCR) system for NO_X reduction unit before being exhausted to the atmosphere.

5.3.1 Step 1 - Identification of Potential Control Technologies

The applicable technologies for controlling GHG emissions from RCH2 include the following:

- Periodic Burner Tune-up - The burners are tuned periodically to maintain optimal thermal efficiency.
- Oxygen Trim Control - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- Use of Hydrogen as a Fuel - Partial replacement of natural gas (methane) with hydrogen (produced as a product in the reaction process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.
- Post-combustion Controls – Carbon capture and storage (see Section 5.7 for BACT discussion)

5.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

All options identified in Step 1 except for post-combustion controls are considered technically feasible. Oxygen trim control and periodic burner tune-ups are currently performed in the existing charge gas heater and will be performed in the new heater. The use of hydrogen as a fuel is current practice in the existing charge gas heater and will be practiced in the new unit.

5.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Oxygen trim control is standard heater technology. The monitoring of the oxygen content of the flue gas is very effective as a means to adjust the inlet air flow to maximize thermal efficiency thereby reducing the formation of GHG.

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. The sale of hydrogen product however is an integral part of the business model of the plant. The substitution of hydrogen also causes an associated increase in NOx emissions because of higher flame temperature and reduced flame stability in the burner. The effectiveness of substituting hydrogen is high, but for the variables listed the effectiveness of this option is reduced. It is anticipated that there will be periods when hydrogen product cannot be sold. During those periods, using hydrogen to the maximum extent possible as a fuel in the burners of RCH2 in place of natural gas reduces GHG emissions.

Currently, periodic tune-ups of the boilers are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as the least effective alternative.

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

The business plan calls for sale of the hydrogen stream, and market conditions will dictate which feeds are used, and the resulting quantity of hydrogen product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice.

Periodic tune-ups of the boilers and preventive maintenance and calibration of fuel flow meters is performed as needed at the plant.

5.3.5 Step 5 – Selection of BACT

The following additional BACT practices are proposed for the charge gas heater:

- Determine CO_2 emissions from the heater based on continuous monitoring of CO_2 emissions. Alternatively, metered fuel consumption and standard emission factors and/or fuel composition and mass balance can be used.
- Maintain operation of the oxygen trim control.
- Calibrate and perform preventive maintenance on the fuel flow meters.
- Perform periodic tune-ups of boiler burners.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the heater or other existing combustion units at the site.

5.4 WASTE HEAT BOILER (WHB2)

Following the regeneration step, the hot gases then pass through a Waste Heat Boiler (WHB2) to recover the heat from the gas stream and generate steam. Supplemental fuel is fired in WHB2 to get the steam to the proper pressure and temperature for use elsewhere on site. The flue gases from WHB2 first pass through a catalytic oxidation unit (CATOX) for CO and VOC control and then to a selective catalyst reduction unit (SCR) for NO_X control. The boiler is an INDECK or equivalent design with duct burners. It is forced draft and the firebox temperature is continuously monitored.

5.4.1 Step 1 – Identification of Potential Control Technologies

The applicable technologies for controlling GHG emissions from WHB2 duct burner include the following:

- Periodic Burner Tune-up - The duct burners and heat recovery steam generators (HRSG) are tuned periodically to maintain optimal thermal efficiency.
- Oxygen Trim Control - Monitoring of oxygen concentration in the flue gas is conducted, and the inlet air flow is adjusted to maximize thermal efficiency.
- Economizer - Use of heat exchanger to recover heat from the exhaust gas to preheat incoming HRSG boiler feedwater to attain industry standard performance (IMO) for thermal efficiency.
- HRSG Blowdown Heat Recovery - Use of a heat exchanger to recover heat from HRSG blowdown to preheat feedwater results in an increase in thermal efficiency.
- Condensate Recovery - Return of hot condensate for use as feedwater to the HRSG. Use of hot condensate as feedwater results in less heat required to produce steam in the HRSG, thus improving thermal efficiency.
- Use of Hydrogen as a Fuel - Partial replacement of natural gas (methane) with hydrogen (produced as a product in the ethane cracking process) reduces CO_2 emissions since combustion of hydrogen does not produce CO_2.

5.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

Oxygen trim control, feasible for stand-alone boilers, is not applicable to duct burners in an HRSG using the combustion unit and regeneration air heater exhaust as the source of combustion air. Therefore, this option was eliminated on the basis of technical infeasibility. All remaining options identified in Step 1 are considered technically feasible. An economizer, condensate return, blowdown heat recovery, use of hydrogen as a fuel, and periodic burner tuneup are also already in use in the existing Propylene Dehydrogenation Unit (PDH1) and will continue to be used in the new Propylene Dehydrogenation Unit (PDH2).

5.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The installation of an economizer to preheat the boiler feedwater (BFW) and a heat exchanger to recover heat from the boiler blowdown are standard items on modern boilers so these two options are ranked first among the options in Step 1.

Substitution of hydrogen for natural gas (methane) results in 100% control of GHG emissions that would otherwise be emitted by each pound of methane replaced. The sale of hydrogen product however is an integral part of the business model of the plant. The substitution of hydrogen also causes an associated increase in NOx emissions because of higher flame temperature and reduced flame stability in the burner. The effectiveness of substituting hydrogen is high, but for the variables listed the effectiveness of this option is reduced. It is anticipated that there will be periods when hydrogen product cannot be sold. During those periods, using hydrogen to the maximum extent possible as a fuel in the burners of WHB2 in place of natural gas reduces GHG emissions.

Currently, periodic tune-ups of the duct burners are performed as needed. The effectiveness of this control option cannot be directly quantified, and is therefore ranked as one of the least effective of the listed options in Step 1.

The recovery of condensate for use as BFW is a known technique but often times is expensive due to the layout of a plant's condensate system therefore it is ranked as one of the least effective of the listed options in Step 1.

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

The business plan calls for sale of the hydrogen stream, and market conditions will dictate which feeds are used, and the resulting quantity of hydrogen product will vary as the feed composition varies. Market conditions will also dictate how much hydrogen can be sold. Therefore, substitution of hydrogen for natural gas as an enforceable GHG BACT alternative is not considered to be a viable control strategy. Rather, a requirement to use hydrogen as fuel in place of natural gas when available and not sold as product is a viable operating practice.

Periodic tune-ups of the duct burners and preventive maintenance and calibration of the fuel flow meters is performed as needed at the plant.

5.4.5 Step 5 – Selection of BACT

As previously stated, condensate recovery, HRSG blowdown heat recovery, and use of an economizer are currently utilized in PDH1 to maximize efficiency and thus reduce GHG emissions. These control practices will be continued as part of the selected BACT. The following additional BACT practices are proposed for WHB2:

- Determine CO_2 emissions from the boiler stack based on continuous monitoring of CO_2 emissions. Alternatively, metered fuel consumption and standard emission factors and/or fuel composition and mass balance can be used.

- Maintain operation of the condensate recovery, HRSG blowdown heat recovery, and economizers.

- Perform periodic tune-ups of duct burners.
- Calibrate and perform preventive maintenance on the fuel flow meters.
- Substitute produced hydrogen that is not sold as product for natural gas to the maximum extent possible in the duct burner or other existing combustion units at the site.

5.5 FLARE (FLARE2)

Process flares are necessary devices for the control of routine and emergency VOC emissions from vents in a chemical process unit. Since the process maximizes the recovery of flare gases, the baseline continuous flared stream consists of equipment and flare header sweeps. As such, the products of combustion contain CO_2. The flare stream also contains unburned CH_4 which is used as pilot gas to combust the VOCs.

5.5.1 Step 1 – Identification of Potential Control Technologies

The RBLC database did not identify any GHG control technologies for control devices such as the flare, particularly since the flare is itself an add-on control unit. Nonetheless, PLP considered the following technologies as potential GHG control measures for the low profile flare in the new ethylene Unit 1594:

Low-Carbon Fuel

Use of fuels containing lower concentrations of carbon generate less CO_2 than other higher-carbon fuels. Typically, gaseous fuels such as natural gas or high-hydrogen plant tail gas contain less carbon, and thus lower CO_2 potential, than liquid or solid fuels such as diesel or coal. Likewise, although flaring carbon-containing vent streams (such as those in the ethylene unit that may contain methane) will necessarily result in CO_2 formation, methane has a global warming potential 21 times higher than that of CO_2. Therefore, control of such streams via flare to reduce methane emissions at the expense of CO_2 generation results in lower overall CO_2e emissions than leaving such streams uncontrolled.

PLP proposes to use natural gas for the flare's pilot gas and as supplemental fuel, if needed, to maintain appropriate vent stream heating value as required by applicable air quality regulations. Liquid and solid fossil fuels are not proposed for use with the flare.

Good Combustion Practice

Good combustion practices for flares include appropriate maintenance of equipment (such as periodic flare tip maintenance) and operating within the recommended heating value and flare tip velocity as specified by its design. Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation.

Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the integrated plant.

PLP will incorporate such combustion practices as recommended by the flare manufacturer.

5.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

Low-Carbon Fuel

- Use of low-carbon fuel is considered technically feasible.

Good Combustion Practice

- Use of good combustion practices is considered technically feasible.

5.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

Low-Carbon Fuel

Material balance principles dictate that the lower the quantity of carbon in the fuel, the lower the resulting CO_2 emissions will be in the combustion stack gases. Therefore, use of low-carbon fuels when the same are available is the next most effective control measure behind energy efficient design. The flare will combust pipeline natural gas in the pilots when in hot standby mode, and when controlling gaseous vent streams, natural gas will be used as supplemental fuel, if needed, to maintain combustion temperatures. PLP will not use liquid or solid fuels in the flare.

Good Combustion Practice

The use of good combustion practices include appropriate maintenance of equipment and operating within the recommended heating value and flare tip velocity as specified by its design. Although good combustion practices do not themselves necessarily directly reduce GHG emissions, using good combustion practices results in longer life of the equipment and more efficient operation. Therefore, such practices indirectly reduce GHG emissions by supporting operation as designed and with consideration of other energy optimization practices incorporated into the integrated plant.

PLP will maintain records of flare tip maintenance and operate the flare within the prescribed heating value and tip velocity ranges.

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

Low-Carbon Fuel

The use of low-carbon fuel is economically and environmentally practical for the proposed project. Combustion of gaseous fuel in lieu of higher carbon-based fuels such as diesel or coal reduces emissions of other combustion products such as NO_x, CO, VOC, PM_{10}, and SO_2, providing environmental benefits. Therefore, low-carbon fuel remains as a viable control technology option

Good Combustion Practices

Good combustion practice effectively supports the proper operation of the flare as a control and safety device. Therefore, good combustion practice also remains as a viable control technology option

5.5.5 Step 5 – Selection of BACT

PLP proposes to incorporate low-carbon fuel and good combustion practices discussed in Section 6.5.1 as BACT for controlling CO_2 emissions from the low profile flare.

5.6 PIPING FUGITIVES (PLANT2)

Emissions from piping components (valves and flanges) associated with this project consist of methane (CH_4) and carbon dioxide (CO_2) which are known in the chemical industry as fugitive emissions. Only 0.18% of the total CO_2e emissions from fugitives are from CO_2. The CO_2e of CH_4 is 99.8% of the total fugitive emissions. Therefore, this discussion will address only CH_4 fugitive emissions, but it should be recognized that any attempt to reduce CH_4 fugitive emissions will also reduce CO_2 emissions.

5.6.1 Step 1 – Identification of Potential Control Technologies

A review of the literature for available control technologies to reduce fugitive emissions resulted in the following available technologies:

1) Installation of leakless components to eliminate sources of fugitive emissions.

2) Implementation a Leak Detection and Repair (LDAR) program to locate and then fix leaking components.

3) Implementation of an alternative monitoring program using remote sensing technology such as infrared cameras.

4) Implementation of an audio/visual/auditory (AVO) monitoring program.

5) Design and construction of facilities with high quality components using materials of construction compatible with the process.

5.6.2 Step 2 – Elimination of Technically Infeasible Alternatives

1) Leakless technology valves are available and in use, but generally only in areas where there are highly toxic materials due to their high cost. In some cases, the use of bellows valves would reduce or eliminate fugitives, but the failure of a bellows valve would necessitate a unit shutdown to replace it and subsequently would generate more emissions than from a leaking valve stem on a conventional valve.

2) LDAR programs have been the traditional means used to control fugitive emissions. Instrumented monitoring for CH_4 emissions is technically feasible.

3) Alternate monitoring programs, such as remote sensing technologies have been proven to be a viable method to detect leaks.

4) Leaking components can be identified through AVO methods. However, this method is best suited to highly odorous gases such as ammonia, sulfur dioxide, and hydrogen cyanide. Given the fact that much of the natural gas used by industrial sources is not odorized (i.e. does not have a compound such as methyl mercaptan added to it), the use of an AVO method to detect CH_4 leaks is limited to seeing or hearing a leak.

5) The use of high quality valves (i.e. valves manufactured to very high quality conditions (i.e. broken down, inspected, and reassembled prior to field installation) would assure that valve stem leakage would be minimized. The cost effectiveness for this additional step is marginal given that the CO_2e emissions from fugitives are only 0.09% of the total CO_2e from the entire project.

5.6.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) Leakless technologies are very effective in eliminating fugitive emissions from valve stems and flanges, though there are still some areas where fugitive emissions can occur (e.g. relief valves).

2) Instrument monitoring (LDAR) is effective for identifying leaking components and is an accepted practice by EPA. Quarterly monitoring with an instrument and a leak definition of 500 ppm is assigned a control effectiveness of 97% by environmental agencies. However such a program is time consuming and is normally only done on a quarterly basis.

3) Remote sensing using infrared imaging has proven very effective for identifying leaks, especially for components in difficult to monitor areas. This method has been the subject of EPA rulemaking as an alternate to EPA Method 21, which is the required instrument monitoring method for LDAR programs.

4) AVO monitoring is very effective due to the frequency of observation opportunities (generally every 8 to 12 hours when processors make their rounds). It is not very effective for low leak rates and is better for identifying large leaks of odorless gases such as methane or smaller leaks of compounds such as ammonia or SO_2 which have low odor thresholds.

5) The use of high quality components is also effective relative to the use of lower quality (i.e. more leak-prone) components but is costly

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

1) Leakless technologies have not generally been regarded as BACT or LAER even for service with highly toxic compounds mainly because a failure of a leakless component results in significant problems in making repairs (i.e. the repair is generally full replacement of the component which is costly and often results in more emissions).

2) Remote monitoring with an infrared instrument, while more costly than the generally accepted and used LDAR program, is often more effective due to its mobility and ability to quickly scan many components in a short period of time.

3) AVO monitoring is very effective for leaks that can be seen or heard, or for leaks of chemicals with low odor thresholds.

4) The use of an instrumented monitoring system such as LDAR is technically feasible but time consuming for the 0.18% of total CO_2e emissions from fugitive sources. Method 21 requires that the instrument be held a certain distance from the component and for a specified period of time, and only one component can be monitored at a time.

5) High quality design is effective for longer term emission control, but often the higher cost of such components does not justify this practice.

5.6.5 Step 5 – Selection of BACT

PLP proposes to conduct remote sensing on an annual basis and daily AVO monitoring for leaks that can be seen or heard to detect methane leaking from the piping components in natural gas service for this project. If a leak is detected it will be repaired following the schedule prescribed by applicable LDAR programs. Though CO_2 is not detectable by remote sensing, any steps taken to reduce methane fugitive emissions will simultaneously reduce emissions of CO_2 present in natural gas.

5.7 BACT FOR SF6 INSULATED ELECTRICAL EQUIPMENT

5.7.1 Step 1 – Identification of Potential Control Technologies

Step 1 of the Top-Down BACT analysis is to identify all feasible control technologies. One technology is the use of state-of-the-art SF6 technology with leak detection to limit fugitive emissions. In comparison to older SF6 circuit breakers, modern breakers are designed as a totally enclosed-pressure system with far lower potential for SF6 emissions. In addition, the effectiveness of leak-tight closed systems can be enhanced by equipping them with a density alarm that provides a warning when 10% of the SF6 (by weight) has escaped. The use of an alarm identifies potential leak problems before the bulk of the SF6 has escaped, so that it can be addressed proactively in order to prevent further release of the gas.
One alternative considered in this analysis is to substitute another, non-greenhouse-gas substance for SF6 as the dielectric material in the breakers. Potential alternatives to SF6 were addressed in the National Institute of Standards and Technology (NTIS) Technical Note 1425, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6.*[15]

5.7.2 Step 2 – Elimination Technically Infeasible Options

According to the report NTIS Technical Note 1425, SF6 is a superior dielectric gas for nearly all high voltage applications.[15] It is easy to use, exhibits exceptional insulation and arc-interruption properties, and has proven its performance by many years of use and investigation. It is clearly superior in performance to the air and oil insulated equipment used prior to the development of SF6-insulated equipment. The report concluded that although "…various gas mixtures show considerable promise for use in new equipment, particularly if the equipment is designed specifically for use with a gas mixture… it is clear that a significant amount of research must be performed for any new gas or gas mixture to be used in electrical equipment." Therefore there are currently no technically feasible options besides use of SF6.

5.7.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

The use of state-of-the-art SF6 technology with leak detection to limit fugitive emissions is the highest ranked control technology that is technically feasible for this application. The circuit breakers utilize continuous monitoring of SF6 gas pressure, and provide a low-pressure alarm directly to the power company in the event of a potential leak.

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[15] Christophorous, L.G., J.K. Olthoff, and D.S. Green, *Gases for Electrical Insulation and Arc Interruption: Possible Present and Future Alternatives to Pure SF6,* NIST Technical Note 1425, Nov.1997.

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

Energy, environmental, or economic impacts were not addressed in this analysis because the use of alternative, non-greenhouse-gas substance for SF6 as the dielectric material in the breakers is not technically feasible.

5.7.5 Step 5 – Selection of BACT

Based on this top-down analysis, PL Propylene LLC concludes that using state-of-the-art enclosed-pressure SF6 circuit breakers with leak detection would be the BACT control technology option. The manufacturing of circuit breakers is regulated by the Electric Reliability Council of Texas (ERCOT). The circuit breakers will be designed to meet the latest of the Institute of Electrical and Electronics (IEEE) and American National Standards Institute (ANSI) C37.013 standards for high voltage circuit breakers.[16] There will be a general certification provided from the manufacturer that demonstrates the IEEE/ANSI standards are met.

The proposed circuit breaker at the generator output will have a low pressure alarm and a low pressure lockout. This alarm will function as an early leak detector that will bring potential fugitive SF6 emissions problems to light before a substantial portion of the SF6 escapes. The lockout prevents any operation of the breaker due to lack of “quenching and cooling” SF6 gas. PL Propylene LLC will monitor emissions in accordance with the requirements of the Mandatory Greenhouse Gas Reporting rules for Electrical Transmission and Distribution Equipment Use.[17] Annual SF6 emissions will be calculated according to the mass balance approach in Equation DD-1 of Subpart DD.

5.8 POST COMBUSTION CONTROLS

5.8.1 Step 1 – Identify Potential Control Technologies

Add-on (post-combustion) control technologies are emerging that will recover CO_2 from gas streams leaving combustion units. For this project, the Charge Gas Heater (RCH2) and the Waste Heat Boiler (WHB2) are capable of having such add-on controls installed. The recovered CO_2 would then be captured and stored such that the CO_2 would not enter the atmosphere. Known as Carbon Capture and Storage (CCS), these emerging technologies generally consist of processes that separate CO_2 from combustion process flue gas, and then inject the CO_2 into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations. Of the emerging CO_2 capture technologies that have been identified, amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. Amine absorption has been applied to 23 commercial plants worldwide mostly for processes in the food and synthesis gas industries. There is one commercial operation using this technology, a 360

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[16] ANSI Standard C37.013, *Standard for AC High-Voltage Generator Circuit Breakers on a Symmetrical Current*.

[17] 40 C.F.R. Pt. 98, Subpt. DD.

short ton per day recovery plant at the Florida Power and Light power plant (3.3% v/v CO_2) located in Bellingham, MA, USA. Other potential absorption and membrane technologies are currently considered developmental and are being tested in small slip stream facilities at large combustion sources such as power plants.

The U.S. Department of Energy's National Energy Technology Laboratory (DOE-NETL) provides the following brief description of state-of-the-art post-combustion CO_2 capture technology and related implementation challenges for power plants:

> …In the future, emerging R&D will provide numerous cost-effective technologies for capturing CO_2 from power plants. At present, however, state-of-the-art technologies for existing systems are essentially limited to amine absorbents. Such amines are used extensively in the petroleum refining and natural gas processing industries… Amine solvents are effective at absorbing CO_2 from combustion unit exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant power output…[18]
>
> The combustion sources in this project are functionally equivalent to combustion sources in a power plant, so this DOE-NETL statement is quite applicable.

The DOE-NETL adds:

> …Separating CO_2 from flue gas streams is challenging for several reasons:
>
> - CO_2 is present at dilute concentrations (13-15 volume percent in coal-fired systems and 3-4 volume percent in gas-fired systems) and at low pressure (15-25 pounds per square inch absolute [psia]), which dictates that a high volume of gas be treated.
> - Trace impurities (particulate matter, sulfur dioxide, nitrogen oxides) in the flue gas can degrade sorbents and reduce the effectiveness of certain CO_2 capture processes.
> - Compressing captured or separated CO_2 from atmospheric pressure to pipeline pressure (about 2,000 psia) represents a large auxiliary power load on the overall plant system.

If CO_2 capture can be achieved at a combustion source, it would need to be routed to a geologic formation capable of long-term storage. The long-term storage potential for a formation is a function of the volumetric capacity the formation and CO_2 trapping mechanisms

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[18] DOE-NETL, *Carbon Sequestration: FAQ Information Portal*, http://extsearch1.netl.doe.gov/search?q=cache:e0yvzjAh22cJ:www.netl.doe.gov/technologies/carbon_seq/FAQs/tech-status.html+emerging+R%26D&access=p&output=xml_no_dtd&ie=UTF-8&client=default_frontend&site=default_collection&proxystylesheet=default_frontend&oe=ISO-8859-1 (last visited Aug. 8, 2011).

within the formation, including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock. The DOE-NETL describes the geologic formations that could potentially serve as CO_2 storage sites as follows:

> "Geologic carbon dioxide (CO_2) storage involves the injection of supercritical CO_2 into deep geologic formations (injection zones) overlain by competent sealing formations and geologic traps that will prevent the CO_2 from escaping."

Current research and field studies are focused on developing better understanding of 11 major types of geologic storage reservoir classes, each having their own unique opportunities and challenges. Understanding these different storage classes provides insight into how the systems influence fluids flow within these systems today, and how CO_2 in geologic storage would be anticipated to flow in the future. The different storage formation classes include: deltaic, coal/shale, fluvial, alluvial, strandplain, turbidite, eolian, lacustrine, clastic shelf, carbonate shallow shelf, and reef. Basaltic interflow zones are also being considered as potential reservoirs. These storage reservoirs contain fluids that may include natural gas, oil, or saline water, any of which may impact CO_2 storage differently.

5.8.2 Step 2 – Eliminate Technically Infeasible Options

5.8.2.1 CO_2 Capture and Compression

The recovery of CO_2 from flue gas is different from other recovery applications. Flue gases are at or near atmospheric pressure and have a very low CO_2 concentration (3-13 vol. %). Monoethanolamine (MEA) is the predominant commercial adsorbent available that is suitable to recover CO_2 from these flue gases. A regenerable alkanolamine process, such as the Fluor Daniel Econamine FG^{SM} process (known as the GAS/SPEC FT-1™ process prior to 1989 when Fluor Daniel purchased the technology from Dow Chemical) is an inhibited MEA process that has shown to be effective at recovering 85-95% of the CO_2 from near atmospheric pressure flue gas streams. However, a 1999 Fluor Daniel paper entitled "Recovery of CO_2 from Flue Gases: Commercial Trends"[19] states that, while this process is reliable for natural gas derived flue gases in plants ranging in size from 6 to 1,000 tonnes/day (te/d) CO_2, no flue gas recovery process can compete in the merchant CO_2 market areas where CO_2 is available in sufficient quantities from by-product sources such as fermentation, natural gas sweetening and ammonia and hydrogen manufacture, or from CO_2 wells.

Recently Skyonic Corp., an Austin-based carbon-capture firm, announced what it says will be the first commercial carbon capture and utilization plant in the country[20]. Officials said the plant will demonstrate the viability of capturing and reusing carbon dioxide as a profitable business-

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[19] Chapel, Dan and Mariz, Carl, "Recovery of CO2 from Flue Gases" Commercial Trends", October, 1999, http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/2b3.pdf

[20] Austin American Statesman, June 25, 2012; http://www.statesman.com/business/technology/construction-to-start-on-carbon-capture-plant-2404123.html

scale venture. Construction is scheduled to begin this summer on the facility, which will be on the site of Capitol Aggregates Ltd. cement plant in San Antonio. Skyonic's carbon-capture technology uses a patented chemistry process that enables power-generation and industrial manufacturing plants to cost-effectively produce energy and products in a cleaner way.

When the San Antonio facility begins operating — projected for 2014 — it will capture 75,000 metric tons of carbon dioxide per year from the cement plant's flues. This quantity is less than 8% of the CO_2 projected to be generated by the PLP facility. The company's SkyMine® technology converts the carbon dioxide released by the flues of industrial facilities into baking soda, hydrochloric acid and other chemicals that can then be sold. The process also filters sulfur oxides, nitrogen dioxide, mercury and other heavy metals from the flue streams.

Therefore, for the purposes of this analysis, it is assumed that the Fluor Daniel process is currently available and proven, making it a good candidate for a carbon capture unit. As seen in Table 5-2, the capital cost to construct a plant large enough to process the flue gases from the PLP facility is in excess of $300 million, with annual operating costs of approximately $15 million.

5.8.2.2 CO_2 Transport

The nearest identified pipeline that could transport CO_2 for enhanced oil recovery (EOR) is the proposed Denbury Green Pipeline. This pipeline will run from the Jackson Dome in Mississippi, to the Hastings, Texas oil field south of Houston which is approximately 20 miles away from the PLP site. According to a statement on their website regarding their Gulf Coast Region CO_2 Sources, Denbury Resources Inc. states that their currently proven resources “are nearly sufficient to provide all the CO_2 for our existing and currently planned phases of operations in the Gulf Coast.” They go on to state that “we have entered into long-term contracts to purchase man made CO_2 from six proposed plants or sources in the Gulf Coast that will emit large volumes of CO_2”[21]. These proposed plants are gasification plants where high purity CO_2 can be recovered as part of the process to generate synthesis gas (hydrogen and carbon monoxide) that can be used to make other products such as methanol, urea, and ammonia. Thus it appears there is little likelihood that the Denbury pipeline, when it is constructed, will be available to receive CO_2 from other sources in the area such as power plants and PLP. The next closest proven location where CO_2 can be used for EOR is the Scurry Area Canyon Reef Operators (SACROC)[22] oilfield (Figure 5-1) near the eastern edge of the Permian Basin in Scurry County, Texas. SACROC is over 350 miles away from the PLP site. There is a closer potential site currently being evaluated. This is the Southeast Regional Carbon Sequestration Partnership (SECARB) site on the Mississippi/Louisiana border, which is about 260 miles from the PLP facility. For the purposes of this analysis it is assumed that a 260 mile pipeline would be required. The expected capital cost (Table 5-2) to install a 260 mile, 18 inch pipeline from PLP

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[21] Denbury Operations-Gulf Coast Region CO2 Resources; http://www.denbury.com/operations/co2-sources/gulf-coast-region/default.aspx

[22] University of Texas at Austin, Bureau of Economic Geology; http://www.beg.utexas.edu/gccc/sacroc.php

to SECARB is approximately $300 million with annual operating costs of approximately $175,000.

5.8.2.3 CO_2 Storage

The feasibility of CCS technology would depend on the availability of a suitable sequestration site. The suitability of potential storage sites is a function of volumetric capacity of the geologic formations and CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock resulting from injection of CO_2 into the formations). Potential environmental impacts resulting from CO_2 injection that still require assessment before CCS technology can be considered feasible include:

- Uncertainty concerning the significance of dissolution of CO_2 into brine;
- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground sources of drinking water (USDW) and/or surface water;
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, USDW, and/or surface water; and
- Potential effects on wildlife.

Potentially suitable storage sites, including EOR sites and saline formations, exist in Texas, Louisiana, and Mississippi. In fact, sites with such recognized potential for some geological storage of CO_2 are located within 15 miles of the proposed project, but such nearby sites have not yet been technically demonstrated with respect to all of the suitability factors described above. One potential storage area is being studied by the Southeast Regional Carbon Sequestration Partnership (SECARB)[23]. The SECARB study started in 2003. Phase I of the study (2003 – 2005) focused on characterizing the geology and potential terrestrial sequestration options in the Southeast. Phase II which ended in 2010 implemented the action plan developed in Phase I by conducting three small-scale and diverse field tests in four locations. Phase III, begun in 2007, is a ten year program to actually demonstrate the ability of the fields to successfully take large volumes of CO_2 over long periods of time. The closest site to the PLP facility is the Cranfield site (Figure 5-1) in Mississippi which is about 260 miles away. As mentioned it is currently under evaluation to determine its capacity for the storage of CO_2 and is not yet ready for operational use. It is estimated that the annual operating costs for such a storage system (Table 5-2) such as SECARB are approximately $4 million. In addition a trust fund, estimated to be $5 million and which would be accrued over a ten year period, would need to be set up to take care of possible future liability issues that might arise after the storage system ceases active operation.

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[23] SECARB Press Release; http://www.sseb.org/secarb.php

5.8.3 Step 3 – Ranking Remaining Technologies Based on Effectiveness

CCS is technically feasible but is not currently effective on a scale large enough to be viable for removing large quantities of CO_2 emissions that would be generated by this project.

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

Based on a CCS cost analysis presented in Table 5-2 done for this project, it is estimated that it will require an upfront capital expenditure of approximately $605 million. This cost is over 50% of the estimated capital cost for the plant modification. Amortized capital costs are expected to be $61 million based on a 20 year life for a post-combustion control system at 8% interest. Annual costs (operating costs plus amortization) are estimated to be approximately $81 million. Thus, for PLP to recover 1,103,858 tons of CO_2 per year the cost would be $82 per ton of CO_2 recovered and stored. In researching to find the value of CO_2 for use in EOR, a February 2008 DOE study[24] estimated that CO_2 used for EOR would have a value of $40 per ton with oil priced at $70 per barrel. This is equivalent to CO_2 at $60 per ton when oil is priced at $100 per barrel. The cost of recovering CO_2 from this project and piping it to an oil field, therefore, is 36% more than it is valued at for EOR. Clearly this is not economically justifiable.

5.8.5 Step 5 – Selection of BACT

CCS, while technically feasible, is not economically viable at this time. CCS therefore does not meet the criteria for BACT that a control method be both technically feasible and economically reasonable.

Additionally, CCS can be eliminated as BACT based on the environmental impacts from a collateral increase of National Ambient Air Quality Standards (NAAQS) pollutants. Implementation of CCS would increase energy usage and thereby increase emissions of NO_X, CO, VOC, PM_{10}, and ammonia by as much as 13% - 17%[25]. The proposed plant is located in the Houston, Galveston, and Brazoria (HGB) ozone nonattainment area and the generation of additional NO_X and VOC, while not considered a major modification, could exacerbate ozone formation in the area. Since the project is located in an ozone non-attainment area, energy efficient technologies are preferred over add-on controls such as CCS that would cause an increase in emissions of NO_X and VOCs to the HGB non-attainment area airshed.

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[24] Storing CO2 with Enhanced Oil Recovery, DOE/NETL-402/1312/02-07-08, February 7, 2008
http://www.netl.doe.gov/kmd/cds/disk44/D-CO2%20Injection/NETL-402-1312.pdf

[25] IPCC, 2005: IPCC Special Report on Carbon Dioxide Capture and Storage. Prepared by Working Group III of the Intergovernmental Panel on Climate Change. Cambridge University Press, Cambridge, United Kingdom and New York, NY, USA. Figure 3.7.

Table 5-1

PL Propylene LLC
EPA RACT/BACT/LAER Clearinghouse
Search Results
Pollutant Group - Greenhouse Gases

RBLC ID	Corporate/Company & Facility Name	Process Code	Process Description	Permit No. Date	Pollutant		Control Method
					CO2	Methane	
LA-0254	Entergy La., Inc. Nine mile Point Elec. Generating Plant	11.31	Auxiliary Boiler (AUX-1)	PSD-LA-752 (08/16/2011)	117 LB/MMBTU	0.002 LB/MMBTU	Proper Operation and Good Combustion Practices
LA-0248	Consolidated Env. Mgt. Inc. - NUCOR Direct Reduction Iron Plant	81.2	DRI-108 - DRI Unit #1 Reformer Main Flue Stack	PSD-LA-751 (01/27/2011)	X		BACT for controlling CO2e emissions from DRI Reformer is good combustion practices which will be adhered to in order to maintain low levels of fuel consumption.
TX-0550	BASF Fina Petrochem. LP BASF Fina NAFTA Region Olefins Complex	50.003	N-10, Catalyst Regeneration Effluent	36644 (02/10/2010)	X		Similar facilities (Marathon Detroit & BP West Coast) used good combustion practices to meet BACT
LA-0148	Red River Environmental Products LLC	11.11	Multiple Hearth Furnaces/Afterburners (coal/natural gas)	PSD-LA-727 (5/28/2008)	X		Afterburner and good combustion practices
TX-0437	BP Amoco Chemical Co. Chocolate Bayou Plant	64.003	Decoke Stack, DDF-101	PSD-TX-854 (10/16/2001)	X		None Indicated
TX-0481	Air Products LP Baytown	19.800	Emergency Generator	PSD-TX-1044/35873 (11/02/2004)	X		None given ; meets BACT
OK-0135	Pryor Plant Chemical Co.	61.999	Carbon Dioxide Vent	2008-100-CPSD (02/23/2009)	X		Good operation practices
AL-0231	Nucor Corp., Nucor Decatur LLC	13.31	Vacuum Degasser Boiler (natural gas)	712-0037 (06/12/2007)	X		None indicated

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Table 5-2

PL Propylene LLC
Carbon Capture and Storage Cost Analysis

CO2 RECOVERY

Capital Cost (capture, compression, and utilities) [3]	*$305,015,385*
Amortized Capital Cost (20 years, 8%)	$31,066,491
Annual Operating Cost (steam, power, electric) [2]	$11,069,368
Annual Chemical Usage (solvent, caustic, activated carbon) [2]	$2,676,111
Annual Waste Disposal (reclaimer, spent carbon) [PLP]	$884,665

CAPITAL COSTS [3]

Year	2000	2005	2009	
Cost Index	100	130	230	(p.5)
Capital Cost	132,615,385	172,400,000	305,015,385	(p.29)

CO2 TRANSPORT, (18-inch diameter, 260 mile length)

Materials [4]	*$70,484,283*
Labor [4]	*$153,560,233*
Miscellaneous [4]	*$65,360,558*
Storage and Controls [4]	*$1,261,268*
Right of Way [4]	*$12,582,325*
Total Capital Cost	*$303,248,666*
Amortized Capital Cost (20 year, 8%)	$30,886,546
Annual Operating Cost [4]	$172,640

CO2 SOURCES (PSD APPLICATION)

GT6	102,494.22	tpy
GT7	102,494.22	tpy
GT8	102,494.22	tpy
GT9	102,494.22	tpy
GT10	102,494.22	tpy
GT11	102,494.22	tpy
RCH2	191,151.72	tpy
RAH2	102,494.22	tpy
WHB2	196,276.43	tpy
FLARE2	32.55	tpy
NG-FUG2	910.70	tpy
Total CO2 Emissions	1,105,831	tpy
	3030	tpd

CO2 STORAGE

Annual Operating Cost	$3,980,991
Liability Trust Fund [4]	*$5,000,000*
Annual Fund Cost [4]	$500,000
Total Annual Storage Cost	*$4,480,991*

INPUT DATA

18	P/L diam., in.	Utilities [2]	10.01	$/ton
260	P/L length, mi.	Chemicals [2]	2.42	$/ton
$1,150,636	CO2 Surge Tank [4]	Waste Disp. [PLP]	0.8	$/ton
$110,632	P/L Control System [4]			
$8,632	Fixed O&M/mile/yr [4]			
20	P/L life, yr.			
90%	CO2 Recovery [5]			

TOTALS

Annualized Cost (operating + amortized), $/yr	**81,236,812**
CO2 Reduction (ton CO2/year), tpy	**995,248**
Annual Control Cost, dollars/ton CO2/year	**$82**

RECOVERY FACTOR

Equipment Life,years	20
Interest Rate	8%
Capital Recovery Factor (CRF)	0.10185221

Data Sources

[1] Reddy, Satish, et.al., "Fluor's Econamine FG Plus™ Technology, May, 2003, http://netl.doe.gov/publications/proceedings/03/carbon-seq/PDFs/169.pdf

[2] Chapel, Dan and Mariz, Carl, "Recovery of CO2 from Flue Gases" Commercial Trends", October, 1999, http://www.netl.doe.gov/publications/proceedings/01/carbon_seq/2b3.pdf

[3] Al-Juaied, Mohammed and Whitmore, Adam, "Realistic Costs of Carbon Capture", July 2009, http://belfercenter.ksg.harvard.edu/files/2009_AlJuaied_Whitmore_Realistic_Costs_of_Carbon_Capture_web.pdf

[4] National Energy Technology Laboratory (NETL), U.S. Department of Energy, Estimating Carbon Dioxide Transport and Storage Costs, March, 2010, http://www.netl.doe.gov/energy-analyses/pubs/qgesstransport.pdf

[PLP] PL Propylene operating data

5 "Report of the Interagency Task Force on Carbon Capture and Storage" (August 2010)

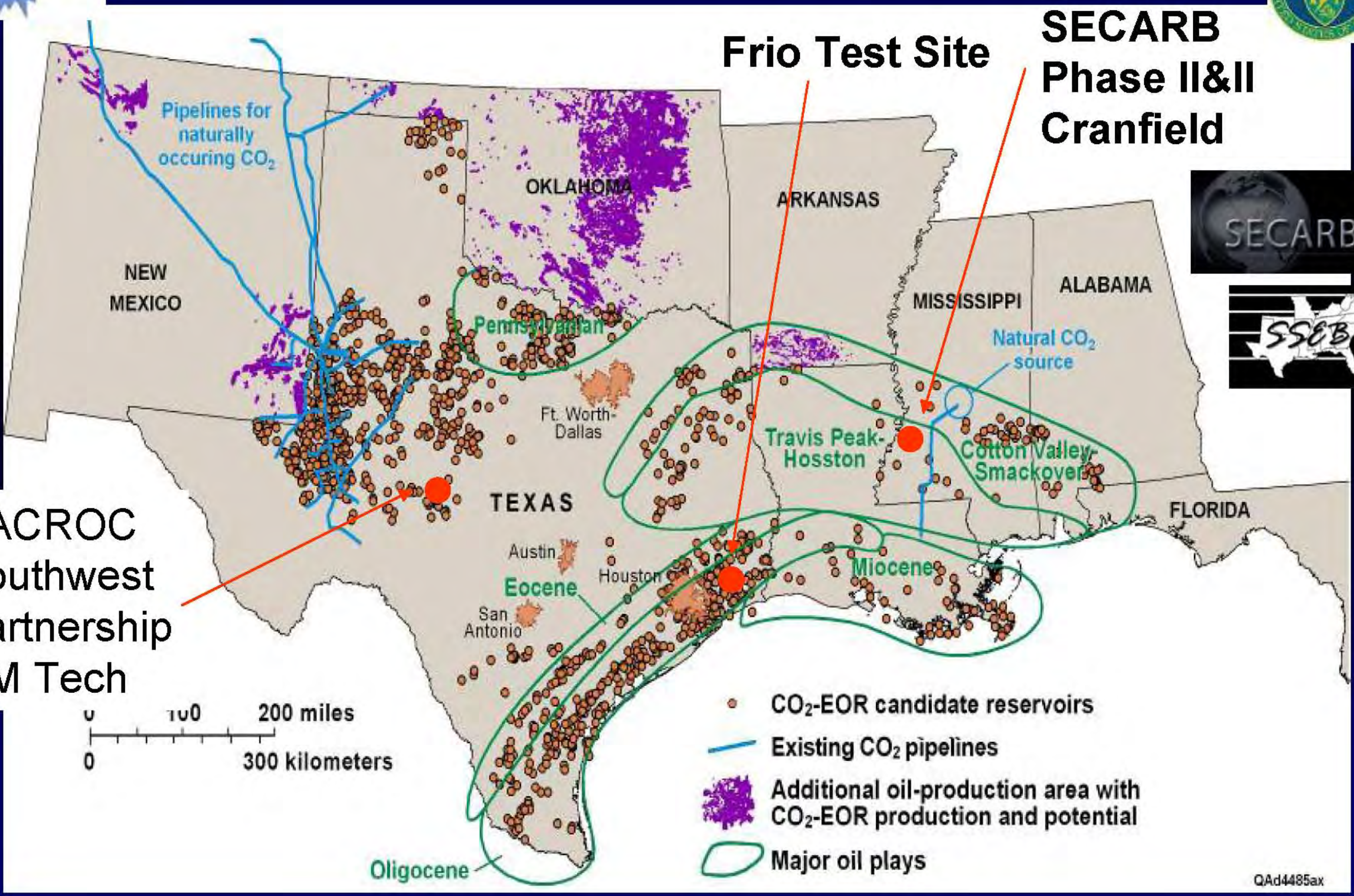
Table 5-3

PL Propylene LLC
GHG BACT MONITORING REQUIREMENTS

Rev. 9-26-12

Emission Unit	Monitored Parameter	Frequency	Limit
All Combustion	Fuel Gas Composition	Weekly	Monitor
	Fuel Gas Flowmeter Preventative Maintennace	Annually	N/A
Process Combustion Units (GT6-GT11)	Differential temperature across burners	Continuous	Less than +/- 158 °F
	External Visual Inspection drain system, air intake, exhaust unit	Daily	No leakage, pluggage, fouling
	General Inspection burners, blades	Every 4000 operating hours	No hot spots, scoring, damage
	Combustion Inspection Hot Gas Inspection	Every 21,000 operarting hours	No hot spots, scoring, damage
Fired Heater (RAH2)	Fire box temperature	Continuous	> 1,000 °F
	Visual inspection of burner and firebox	Annually	No burner damage or unusual flame patterns
	Fuel gas pressure	Continuous	< 70 psig
Fired Heater (RCH2)	CO2 Emissions Monitor	Continuous	Below permit limit
	Visual inspection of burner and firebox	Annually	No burner damage or unusual flame patterns
	Fuel gas pressure	Continuous	< 70 psig
Waste Heat Boiler (WHB2)	CO2 Emissions Monitor	Continuous	Below permit limit
	Visual inspection of burner and firebox	Annually	No burner damage or unusual flame patterns
	Fuel gas pressure	Continuous	< 70 psig
Flare (FLARE2)	Pilots	Continuous	Flame sensors show flame
	Flare gas heating value	Continuous	> 300 BTU/SCF
	Flare gas velocity	Continuous	< 600 ft/sec
Piping Fugitives (PLANT2)	Inspection using remote sensing instrument	Annually	No visible leaks
	Leaks using AVO	Daily	No audible or visual leaks
SF6 Breakers (SF6-FUG)	Gas Detector	Continuous	Low pressure

GCCC Field Tests for Monitoring and Verification Technologies DOE NETL support



Frio Test Site

SECARB Phase II&II Cranfield

SACROC Southwest Partnership NM Tech

6.0 OTHER PSD REQUIREMENTS

6.1 IMPACTS ANALYSIS

An impacts analysis is not being provided with this application in accordance with EPA's recommendations:

> *Since there are no NAAQS or PSD increments for GHGs, the requirements in sections 52.21(k) and 51.166(k) of EPA's regulations to demonstrate that a source does not cause contribute to a violation of the NAAQS are not applicable to GHGs. Therefore, there is no requirement to conduct dispersion modeling or ambient monitoring for CO_2 or GHGs.*[26]

6.2 GHG PRECONSTRUCTION MONITORING

A pre-construction monitoring analysis for GHG is not being provided with this application in accordance with EPA's recommendations:

> *EPA does not consider it necessary for applicants to gather monitoring data to assess ambient air quality for GHGs under section 52.21(m)(1)(ii), section 51.166(m)(1)(ii), or similar provisions that may be contained in state rules based on EPA's rules. GHGs do not affect "ambient air quality" in the sense that EPA intended when these parts of EPA's rules were initially drafted. Considering the nature of GHG emissions and their global impacts, EPA does not believe it is practical or appropriate to expect permitting authorities to collect monitoring data for purpose of assessing ambient air impacts of GHGs.*[27]

6.3 ADDITIONAL IMPACT ANALYSIS

40 CFR §52.21(o) requires an Additional Impacts Analysis for projects that are subject to PSD review.

> (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.

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[26] *EPA, PSD, and Title V Permitting Guidance for Greenhouse Gases* at 48-49

[27] *Id.* At 49

> (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) Visibility Monitoring. 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.

6.3.1 Visibility, Soils, and Vegetation

The proposed project will be constructed at an existing industrial site and utilize primarily existing infrastructure. The nearest Federal Class I Area is the Caney Creek Wilderness Area which is approximately 350 miles from the facility. GHGs have not been demonstrated to have any direct impact on visibility, soils, and vegetation other than their potential impact associated with global warming, which according to EPA guidance is not required to be evaluated for additional impacts analysis or Class I area provisions.

The proposed increases for all other regulated pollutants do not result in a significant increase in air contaminants, therefore the project is not subject to PSD review for any other pollutant. As noted in the Air Quality Impacts Analysis for the project, the proposed emissions will be below the respective Significant Impact Level or National Ambient Air Quality Standards for all other pollutants. The emissions from the proposed facilities will not have an impact on the area.

6.3.2 Associated Growth

The proposed project will not significantly affect residential, commercial, or industrial growth in the area. The proposed project will be constructed at an existing industrial site located at a major industrial complex. Approximately 30 new jobs will be created at the completion of the proposed project. The residential and commercial areas near the plant site are existing and well-established neighborhoods located in the cities of Houston and Pasadena, Texas. Any individuals relocating to the area for employment would result in a negligible impact on the existing infrastructure.

Appendix A

GHG Emissions Summary and Calculations

PL Propylene LLC
GHG Emissions

Appendix A-1
Summary

Source	FIN	EPN	Firing Rate	Firing Rate	CO2	CH4	N2O	CO2e
			mmBTU/hr	MMBtu/yr	mt/yr	mt/yr	mt/yr	st/yr
Gas Turbine MSS (new)	GT6	GT6	200	14,400	763.49	0.01	0.001	842.42
Gas Turbine MSS (new)	GT7	GT7	200	14,400	763.49	0.01	0.001	842.42
Gas Turbine MSS (new)	GT8	GT8	200	14,400	763.49	0.01	0.001	842.42
Gas Turbine MSS (new)	GT9	GT9	200	14,400	763.49	0.01	0.001	842.42
Gas Turbine MSS (new)	GT10	GT10	200	14,400	763.49	0.01	0.001	842.42
Gas Turbine MSS (new)	GT11	GT11	200	14,400	763.49	0.01	0.001	842.42
Charge Gas Heater (new)	RCH2	RCH2	373	3,267,480	173,241.79	3.27	0.33	191,151.72
Gas Turbine (new)	*GT6*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Gas Turbine (new)	*GT7*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Gas Turbine (new)	*GT8*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Gas Turbine (new)	*GT9*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Gas Turbine (new)	*GT10*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Gas Turbine (new)	*GT11*	*WHB2*	*200*	*1,737,600*	*92,127.55*	*1.74*	*0.17*	*101,651.80*
Regen Air Heater (new)	*RAH2*	*WHB2*	*200*	*1,752,000*	*92,891.04*	*1.75*	*0.18*	*102,494.22*
Waste Heat Boiler (new)	*WHB2*	*WHB2*	*383*	*3,355,080*	*177,886.34*	*3.36*	*0.34*	*196,276.43*
Waste Heat Boiler TOTAL		WHB2		15,532,680	823,542.69	15.53	1.55	908,681.44
Natural Gas Fugitives (new)	NG-FUG2	NG-FUG2	NA	NA	1.47	38.16	0.00	884.90
Flare (new) Routine	*FLARE2MSS*	*FLARE2*	*NA*	*NA*	*8.01*	*0.02*	*0.00*	*9.37*
Flare (new) MSS	*FLARE2*	*FLARE2*	*NA*	*NA*	*19.82*	*0.06*	*0.00*	*23.18*
Flare TOTAL		FLARE2						32.55
SF6 Electrical Equipment	SF6-FUG	SF6-FUG	NA	NA	NA	NA	NA	25.80
Total					1,001,395	57	2	1,105,831

PL Propylene LLC
GHG Emissions

Appendix A-2

Source:
Natural Gas Combustion Sources

Description:
CO2e theoretical maximum emissions estimate based on EPA Tier 1 calculation methodology.

40 CFR 98 Equation C-1 (CO2)
CO2 (metric ton/yr) = Conversion 0.001 (metric ton/kg) * Fuel (scf/yr) * HHV (mmBtu/scf) * EF (kg CO2/mmBtu)

40 CFR 98 Equation C-8(CH4 & N2O)
CH4 or N2O (metric ton/yr) = Conversion 0.001 (metric ton/kg) * Fuel (scf/yr) * HHV (mmBtu/scf) * EF (kg CO2/mmBtu)

40 CFR 98 Equation A-1)
CO2e (metric ton/yr) = GHG (metric ton/yr) * GWP (Global Warming Potential)

Basis

Source=	CU6 - CU11 MSS	CU6 - CU11	RCH2	RAH2	WHB2		
Emission Point=	CU6 - CU11	WHB2	RCH2	WHB2	WHB2		
Firing Rate=	200	200	373	200	383	mmBTU/hr	Design
Fuel Source=	Nat Gas	Nat Gas	Nat Gas	Nat Gas	Nat Gas		Design
HHV=	1.028E-03	1.028E-03	1.028E-03	1.028E-03	1.028E-03	mmBTU/scf	40 CFR 98 Table C-1
Fuel=	1.401E+07	1.690E+09	3.178E+09	1.704E+09	3.264E+09	scf/yr	Calculated
Operating Factor=	72	8688	8760	8760	8760	hr/yr	Design

Factors

Convert kg to mt=	0.001	0.001	0.001	0.001	0.001	mt/kg	Constant
Convert from mt to t=	1.1023	1.1023	1.1023	1.1023	1.1023	t/mt	Constant
Emission Factor, CO2=	53.02	53.02	53.02	53.02	53.02	kg CO2/mmBTU	40 CFR 98 Table C-1
Emission Factor, CH4=	1.0E-03	1.0E-03	1.0E-03	1.0E-03	1.0E-03	kg CH4/mmBTU	40 CFR 98 Table C-2
Emission Factor, N2O=	1.0E-04	1.0E-04	1.0E-04	1.0E-04	1.0E-04	kg N2O/mmBTU	40 CFR 98 Table C-2
GWP=	1	1	1	1	1	CO2	40 CFR 98 Table A-1
	21	21	21	21	21	CH4	40 CFR 98 Table A-1
	310	310	310	310	310	N2O	40 CFR 98 Table A-1

Calculations

CO2=	763.488	92127.552	173241.79	92891.04	177886.34	mt/yr	40 CFR 98 EQ C-1
CO2e=	763.488	92127.552	173241.79	92891.04	177886.34	mt/yr	40 CFR 98 EQ A-1
CH4=	0.01	1.74	3.27	1.75	3.36	mt/yr	40 CFR 98 EQ C-8
CO2e=	0.30	36.49	68.62	36.79	70.46	mt/yr	40 CFR 98 EQ A-1
N2O=	0.00	0.17	0.33	0.18	0.34	mt/yr	40 CFR 98 EQ C-8
CO2e=	0.45	53.87	101.29	54.31	104.01	mt/yr	40 CFR 98 EQ A-1
Total CO2e=	**764**	**92,218**	**173,412**	**92,982**	**178,061**	**mt/yr**	CO2e (CO2 + CH4 + N2O)
Total CO2e=	**842**	**101,652**	**191,152**	**102,494**	**196,276**	**ton/yr**	
Annual Firing Rate=	14,400	1,737,600	3,267,480	1,752,000	3,355,080	MMBtu/yr	
Emission Factor, Net=	**117.0**	**117.0**	**117.0**	**117.0**	**117.0**	**lb CO2e/mmBtu**	CO2e/Firing Rate(ann)

PL Propylene LLC
GHG Emissions

Appendix A-3

Source:

Natural Gas Fugitive Emissions

Description:

CO2e from natural gas piping valves and connections.

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2[2] (tpy)	Methane[3] (tpy)	Total (stpy)
NG-FUG2	Valves	Gas/Vapor	1500	0.123	1.23	31.75	
	Flanges	Gas/Vapor	3500	0.017	0.40	10.24	
	Relief Valves	Gas/Vapor	2	0.196	0.003	0.067	
	Sampling Connections [5]	Gas/Vapor	2	0.123	0.002	0.042	
GHG Mass-Based Emissions					1.63	42.06	
Global Warming Potential[4]					1	21	
CO_2e Emissions					1.63	883.28	***884.9***

Note

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting*
2. *CO_2* emissions based on vol% of CO_2 in natural gas 1.33% from natural gas analysis
3. *CH_4 emissions based on vol% of CH_4 in natural gas* 94.44% from natural gas analysis
4. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
5. *No emission factor in Table W-1a so conservatively used valve emission factor.*

Example calculation:

50 valve	0.123 scf gas	0.0133 scf CO_2	lbmole	44.01 lb CO_2	8760 hr	ton =	1.23 ton/yr
	hr * valve	scf gas	385.5 scf	lbmole	yr	2000 lb	

PL Propylene LLC
GHG Emissions

Appendix A-4-1

Source:
Flaring Emissions

Description:
CO2e from routine process flaring.

Emission Point:
FLARE2

40 CFR 98 Equation Y-2 (CO2), Y-4(CH4) & Y-Y-5 (N2O)

CO2 (mt/yr) = Flare Combustion Efficiency *Unit Conversion factor*Volume Flare Gas Combusted *Flare Gas Higher Heating Value *Default CO2 Emmision Factor [40 CFR 98.253 (Eq. Y-2)]

Volume Flare Gas(MMscf) = 0.000001 * Flare Gas Mass Flow *Molar Vol. Conv. Factor /Flare Gas Mol. Wt.

BTU/scf = Heating Value (BTU/lb) * lb/gm Conv. * gms/kg Conv.*Flare Gas MW*kg-mol/scf Conv.

CH4 (mt/yr) = [(CO2 Emission Rate) * EmF $_{CH4}$ from Table C-2)/EmF CO2] + CO2 Emission Rate*0.02/0.98*16/44*f_{CH4} 40 [CFR 98.253 (Eq. 4)]

N2O (mt/yr) = CO2 Emission Rate*Default N2O Emission Factor/Default CO2 Emission Factor [40 CFR 98.253 (Eq. 5)]

EF (kg GHG/MMBtu Nat Gas) = 53.02 for CO2, 0.001 for CH4, 0.0001 for N2O [40 CFR 98 Table C-1 & C-2]

40 CFR 98 Equation A-1)

CO2e (metric ton/yr) = GHG (metric ton/yr) * GWP

GWP = 1.0 for CO2, 21.0 for CH4, 310.0 for N2O

Flare Gas Mass Flow	2,082,725	kg/yr	Material Balance
Flare Gas Heating Value	29706	BTU/lb	
Flare Gas Mol. Wt.	41.92	kg/kg-mol	
Flare Efficiency	98%		Design
Unit Conversion Factor	0.001	mt/kg	Constant
Molar vol. Conv. Factor	849.5	scf/kg-mol	Conversion
Default CO2 Emission Factor	60	kg CO2/MMBtu	
Default Wt. Frac. C in Flare Gas	0.4		
Conv. Factor	1.00E-06		Constant
Unit Conversion Factor	0.001	mt/kg	Constant
EF_{NG}, CO2=	53.02	kg CO2/mmBTU	EF=Emission Factor
EF_{NG}, CH4=	1.0E-03		
EF_{NG}, N2O=	1.0E-04		
GWP=	1	CO2	GWP=Global Warming Potential
	21	CH4	
	310	N2O	
Conv. Factor	1000	gm/kg	
Conv. Factor	454	gm/lb	
Conv. Factor	1.1	t/mt	
Volume Flare Gas Flow	42	MMscf/yr	
Flare Gas Heating Value	3.23	BTU/scf	

Calculations

CO2 Emissions =	8.01	mt/yr	8.81	st/yr
CO2e Emissions =	8.01	mt/yr	8.81	st/yr
CH4 Emissions =	0.02	mt/yr	0.03	st/yr
CO2e Emissions =	0.50	mt/yr	0.55	st/yr
N2O Emissions =	1.3E-05	mt/yr	1.5E-05	st/yr
CO2e Emissions =	4.E-03	mt/yr	5.E-03	st/yr
Total GHG Emissions =	**8.04**	**mt/yr**	**8.84**	**st/yr**
Total CO2e Emissions =	**8.52**	**mt/yr**	**9.37**	**st/yr**

PL Propylene LLC
GHG Emissions

Appendix A-4-2

Source:
Flaring Emissions

Description:
CO2e from maintenance startup and shutdown flaring.

Emission Point:
FLARE2

40 CFR 98 Equation Y-2 (CO2), Y-4(CH4) & Y-Y-5 (N2O)

CO2 (mt/yr) = Flare Combustion Efficiency *Unit Conversion factor*Volume Flare Gas Combusted *Flare Gas Higher Heating Value *Default CO2 Emmision Factor [40 CFR 98.253 (Eq. Y-2)]

Volume Flare Gas(MMscf) = 0.000001 * Flare Gas Mass Flow *Molar Vol. Conv. Factor /Flare Gas Mol. Wt.

BTU/scf = Heating Value (BTU/lb) * lb/gm Conv. * gms/kg Conv.*Flare Gas MW*kg-mol/scf Conv.

CH4 (mt/yr) = [(CO2 Emission Rate) * EmF $_{CH4}$ from Table C-2)/EmF CO2] + CO2 Emission Rate*0.02/0.98*16/44*f_{CH4} 40 [CFR 98.253 (Eq. 4)]

N2O (mt/yr) = CO2 Emission Rate*Default N2O Emission Factor/Default CO2 Emission Factor [40 CFR 98.253 (Eq. 5)]

EF (kg GHG/MMBtu Nat Gas) = 53.02 for CO2, 0.001 for CH4, 0.0001 for N2O [40 CFR 98 Table C-1 & C-2]

40 CFR 98 Equation A-1)

CO2e (metric ton/yr) = GHG (metric ton/yr) * GWP

GWP = 1.0 for CO2, 21.0 for CH4, 310.0 for N2O

Flare Gas Mass Flow	7,241,300	kg/yr	Material Balance
Flare Gas Heating Value	21130	BTU/lb	
Flare Gas Mol. Wt.	44.05	kg/kg-mol	
Flare Efficiency	98%		Design
Unit Conversion Factor	0.001	mt/kg	Constant
Molar vol. Conv. Factor	849.5	scf/kg-mol	Conversion
Default CO2 Emission Factor	60	kg CO2/MMBtu	
Default Wt. Frac. C in Flare Gas	0.4		
Conv. Factor	1.00E-06		Constant
Unit Conversion Factor	0.001	mt/kg	Constant
EF_{NG}, CO2=	53.02	kg CO2/mmBTU	EF=Emission Factor
EF_{NG}, CH4=	1.0E-03		
EF_{NG}, N2O=	1.0E-04		
GWP=	1	CO2	GWP=Global Warming Potential
	21	CH4	
	310	N2O	
Conv. Factor	1000	gm/kg	
Conv. Factor	454	gm/lb	
Conv. Factor	1.1	t/mt	
Volume Flare Gas Flow	140	MMscf/yr	
Flare Gas Heating Value	2.41	BTU/scf	

Calculations

CO2 Emissions =	19.82	mt/yr	21.80	st/yr
CO2e Emissions =	19.82	mt/yr	21.80	st/yr
CH4 Emissions =	0.06	mt/yr	0.07	st/yr
CO2e Emissions =	1.24	mt/yr	1.37	st/yr
N2O Emissions =	3.3E-05	mt/yr	3.6E-05	st/yr
CO2e Emissions =	1.E-02	mt/yr	1.E-02	st/yr
Total GHG Emissions =	**19.88**	**mt/yr**	**21.86**	**st/yr**
Total CO2e Emissions =	**21.07**	**mt/yr**	**23.18**	**st/yr**

Appendix A-5

GHG Emission Calculations - Electrical Equipment Insulated With SF_6

New insulated circuit breaker SF_6 capacity =	72 lb
Breaker Quantity =	6
Estimated annual SF_6 leak rate =	0.5% by weight
Estimated annual SF_6 emission rate =	0.00018 ton/yr
Estimated Total annual SF_6 emission rate =	0.00108 ton/yr
Global Warming Potential[1] =	23,900
Estimated annual CO_2e emission rate =	4.3 ton/yr
Estimated Total Annual CO_2e emission rate =	25.8 ton/yr

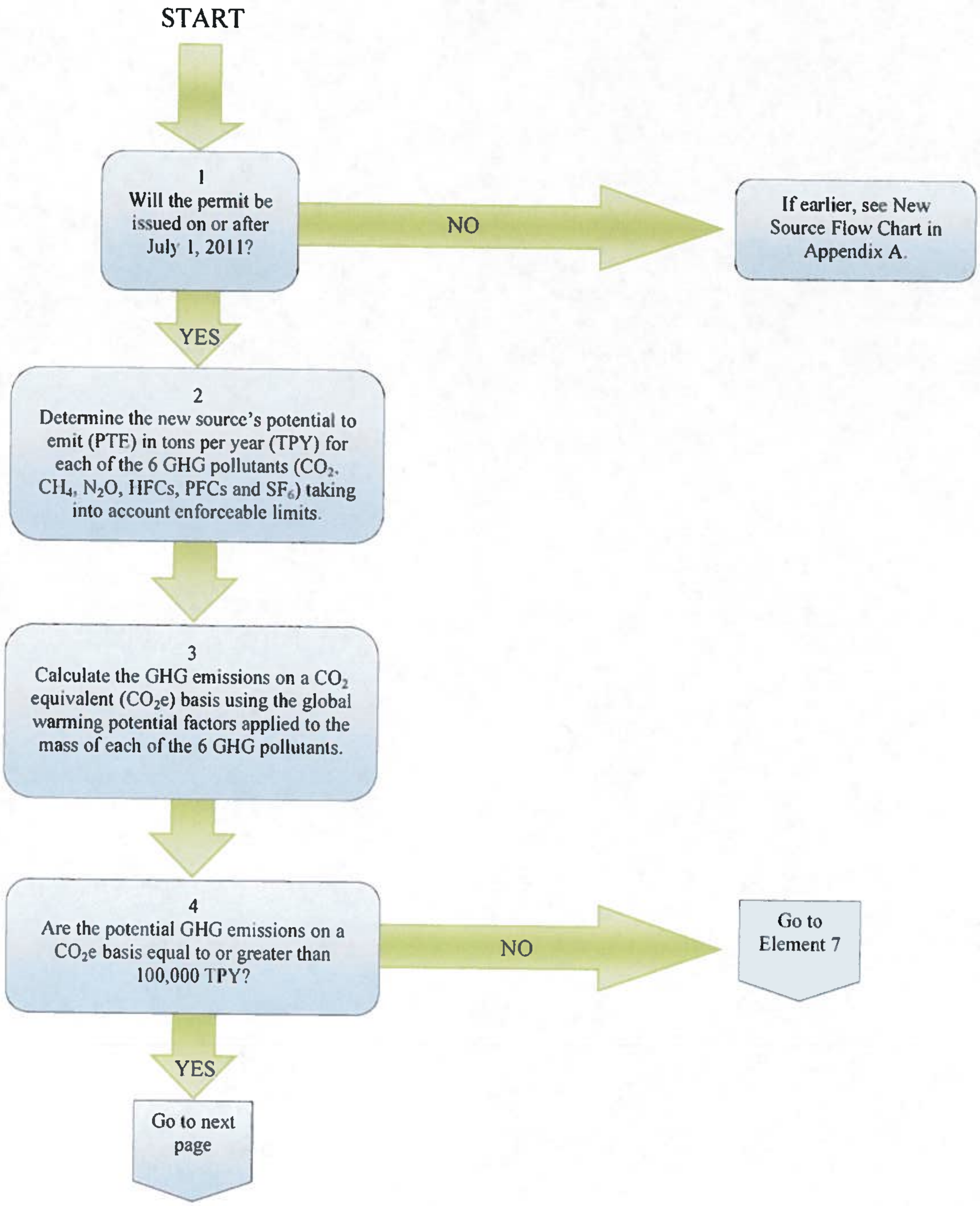
Note

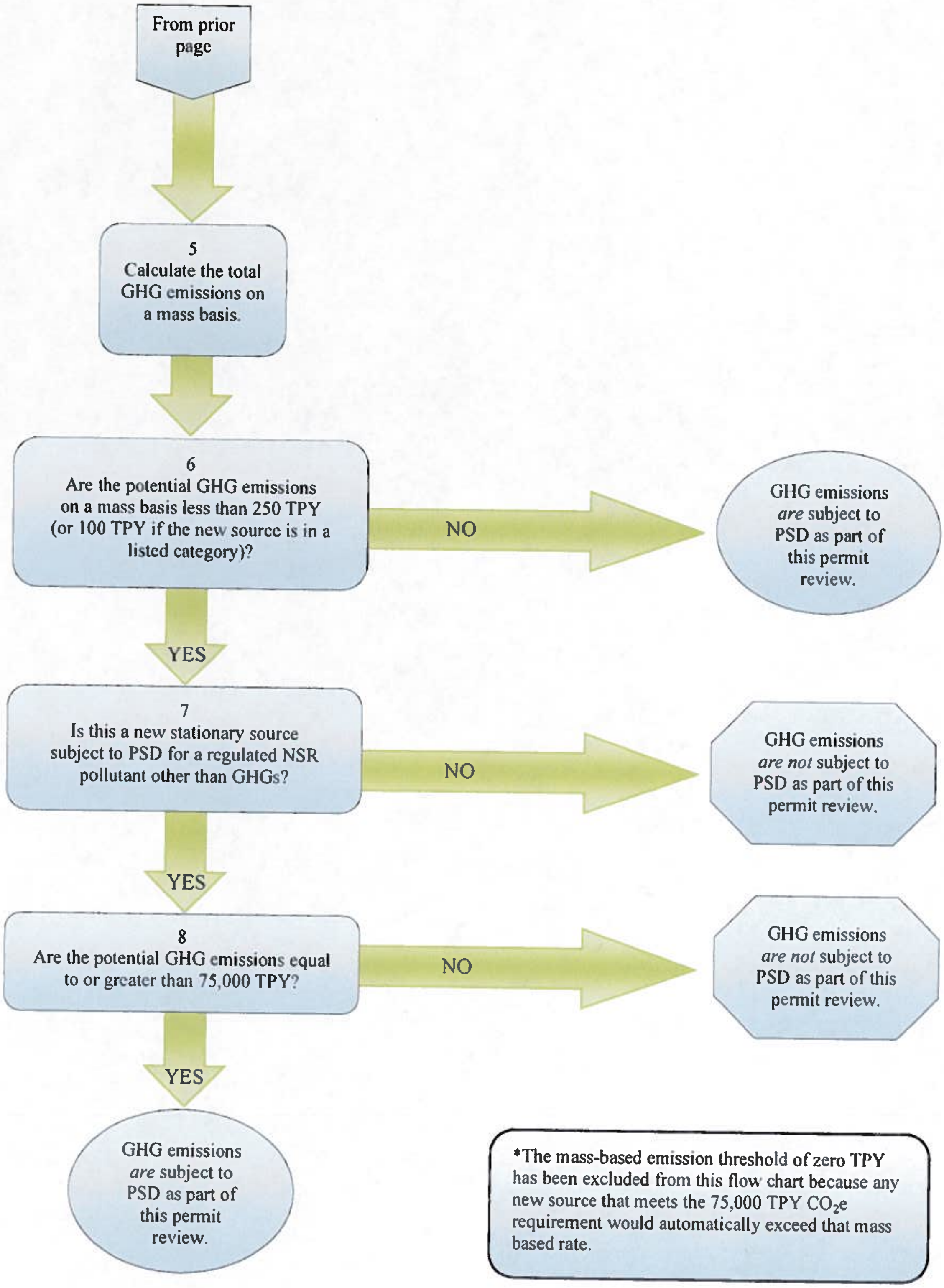
1. Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

Appendix B

GHG PSD Applicability Flowchart

Appendix B. GHG Applicability Flow Chart – New Sources (On or after July 1, 2011)





*The mass-based emission threshold of zero TPY has been excluded from this flow chart because any new source that meets the 75,000 TPY CO_2e requirement would automatically exceed that mass based rate.

Appendix C

GHG Netting Tables

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	18999	Application Submittal Date:	01/15/2012
Company	PL Propylene LLC		
RN:	RN102576063	Facility Location:	Houston
City		County:	Harris
Permit Unit I.D.:	PL Propylene LLC	Permit Name:	PL Propylene LLC
Permit Activity:			
Project or Process Description:	Authorize Added Combustion Sources		

Complete for all pollutants with a project emission increase.	**POLLUTANTS**						
	Ozone		**CO**	**SO_2**	**PM**	**GHG**	**CO_2e**
	NOx	**VOC**					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	**This form for GHG only**					> 100,000	> 100,000
Proposed project increases (tpy from 2F)[3]						1,103,902	1,105,831
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)	Yes						
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:		12/1/12					
5 years prior to start of construction:		12/1/07	Contemporaneous				
estimated start of operation:		3/1/14	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						Note 4	Note 4
FNSR applicable? (yes or no)						Yes	Yes

1. Other PSD pollutants
2. Nonattainment major source is defined in Table 1 in 30 TAC 116.12(11) by pollutant and county. PSD thresholds are found in 40 CFR §51.166(b)(1).
3. Sum of proposed emissions minus baseline emissions, increases only. Nonattainment thresholds are found in Table 1 in 30 TAC 116.12(11) and PSD thresholds in 40 CFR §51.166(b)(23).
4. Since there are no contemporaneous decreases which would potentially affect PSD applicability and an impacts analysis is not required for GHG emissions, contemporaneous emission changes are not included on this table.

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

Signature	Title	Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant(1):	**GHG**	**Permit:**	**18999**
Baseline Period:	**Jan-11**	**to**	**Dec-11**

					A	**B**				
Affected or Modified Facilities(2)			**Permit No.**	**Actual Emissions (3)**	**Baseline Emissions(4)**	**Proposed Emissions(5)**	**Projected Actual Emissions**	**Difference (B-A)(6)**	**Correction(7)**	**Project Increase(8)**
	FIN	**EPN**								
	GT6 MSS	GT6	18999	0	0	842		842		842
	GT7 MSS	GT7	18999	0	0	842		842		842
	GT8 MSS	GT8	18999	0	0	842		842		842
	GT9 MSS	GT9	18999	0	0	842		842		842
	GT10 MSS	GT10	18999	0	0	842		842		842
	GT11 MSS	GT11	18999	0	0	842		842		842
	GT6	WHB2	18999	0	0	101,554		101,554		101,554
	GT7	WHB2	18999	0	0	101,554		101,554		101,554
	GT8	WHB2	18999	0	0	101,554		101,554		101,554
	GT9	WHB2	18999	0	0	101,554		101,554		101,554
	GT10	WHB2	18999	0	0	101,554		101,554		101,554
	GT11	WHB2	18999	0	0	101,554		101,554		101,554
	RCH2	RCH2	18999	0	0	190,968		190,968		190,968
	RAH2	WHB2	18999	0	0	102,396		102,396		102,396
	WHB2	WHB2	18999	0	0	196,088		196,088		196,088
	NG-FUG2	NG-FUG	18999	0	0	44		44		44
	FLARE2	FLARE2	18999	0	0	9		9		9
	FLARE2 MSS	FLARE2	18999	0	0	22		22		22
	SF6-FUG	SF6-FUG	18999	0	0	0.00		0.01		0.01
									Total	1,103,902

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) - Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	**CO2e**	**Permit:**	**18999**
Baseline Period:	**Jan-11**	**to**	**Dec-11**

Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3]	Baseline Emissions[4]	Proposed Emissions[5]	Projected Actual Emissions	Difference (B-A)[6]	Correction[7]	Project Increase[8]
					A	B				
	FIN	EPN								
	GT6 MSS	GT6	18999	0	0	842		842		842
	GT7 MSS	GT7	18999	0	0	842		842		842
	GT8 MSS	GT8	18999	0	0	842		842		842
	GT9 MSS	GT9	18999	0	0	842		842		842
	GT10 MSS	GT10	18999	0	0	842		842		842
	GT11 MSS	GT11	18999	0	0	842		842		842
	GT6	WHB2	18999	0	0	101,652		101,652		101,652
	GT7	WHB2	18999	0	0	101,652		101,652		101,652
	GT8	WHB2	18999	0	0	101,652		101,652		101,652
	GT9	WHB2	18999	0	0	101,652		101,652		101,652
	GT10	WHB2	18999	0	0	101,652		101,652		101,652
	GT11	WHB2	18999	0	0	101,652		101,652		101,652
	RCH2	RCH2	18999	0	0	191,152		191,152		191,152
	RAH2	WHB2	18999	0	0	102,494		102,494		102,494
	WHB2	WHB2	18999	0	0	196,276		196,276		196,276
	NG-FUG2	NG-FUG	18999	0	0	885		885		885
	FLARE2	FLARE2	18999	0	0	9		9		9
	FLARE2 MSS	FLARE2	18999	0	0	23		23		23
	SF6-FUG	SF6-FUG	18999	0	0	26		26		26
									Total	1,105,831

1. Individual Table 2F's should be used to summarize the project emission increase for each criteria pollutant.
2. Emission Point Number as designated in NSR Permit or Emissions Inventory.
3. All records and calculations for these values must be available upon request.
4. Correct actual emissions for currently applicable rule or permit requirements, and periods of non-compliance. These corrections, as well as any MSS previously demonstrated under 30 TAC 101, should be explained in the Table 2F supplement.
5. If projected actual emission is used it must be noted in the next column and the basis for the projection identified in the Table 2F supplement.
6. Proposed Emissions (column B) - Baseline Emissions (column A).
7. Correction made to emission increase for what portion could have been accommodated during the baseline period. The justification and basis for this estimate must be provided in the Table 2F supplement.
8. Obtained by subtracting the correction from the difference. Must be a positive number.
9. Sum all values for this page.

Appendix D

EPA Completeness Determination Letter

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
REGION 6
1445 ROSS AVENUE, SUITE 1200
DALLAS, TX 75202-2733

AUG 21 2012

Mr. Vance Darr
Environmental Manager
PL Propylene LLC
9822 La Porte Freeway
Houston, TX 77017

Subject: Completeness Determination for the PL Propylene LLC Greenhouse Gas Prevention of Significant Deterioration (PSD) Permit Application

Dear Mr. Darr:

This letter is in response to your application received by this office on February 3, 2012 for a Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit. After our initial review of the application, we determined additional information was necessary in order to continue the processing of the permit. Accordingly, we sent notification that the application was determined to be incomplete on May 4, 2012. Based on our review of your response and the supplemental information provided on July 24, 2012, we have determined that your application is complete pursuant to 40 CFR 124.3(c).

We are drafting a proposed determination on the issuance of a GHG PSD permit. EPA will publish a public notice of that proposed determination and allow for at a minimum a 30-day public comment period. In addition, documents important to the proposed determination such as the draft permit will be made available for review by the public during the public comment period. EPA will consider and respond to all significant comments in making the final decision on the application and keep a record of the persons commenting and the issues being raised during the public participation process. As we develop our proposed determination, it may be necessary for EPA to request additional clarifying or supporting information. If the supporting information substantially changes the original scope of the permit application, an amendment or new application may be required.

Although not required as a part of our completeness determination, the EPA may not issue a final permit without determining its action will have no effect on threatened or endangered species and their designated critical habitat or until it has completed consultation under Section 7 of the Endangered Species Act (16 USC 1536). In addition, the EPA must undergo consultation pursuant to Section 106 of the National Historic Preservation Act (16 USC 470f). To expedite these consultations, the EPA requests that permit applicants provide a Biological Assessment and a cultural resources report covering the project and action area to the EPA, If you have any questions regarding the review of your permit application, please contact Aimee Wilson of my staff at (214) 665-7596 or wilson.aimee@epa.gov.

Sincerely yours,

Carl E. Edlund, P.E.
Director
Multimedia Planning and
Permitting Division

cc: Mr. Mike Wilson, P.E., Director
Air Permits Division
Texas Commission on Environmental Quality