PETROLOGISTICS

PL Propylene LLC
9822 La Porte Freeway
Houston, TX 77017

July 30, 2012

Mr. Carl E. Edlund, P.E., Director
Multimedia Planning and Permitting Division
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

Re: Additional Information for Greenhouse Gas PSD Permit Application
PL Propylene LLC
Houston, Harris County, Texas
TCEQ Account Number HG-0035-U

PL Propylene is providing an addendum to the GHG PSD permit application submitted on February 3, 2012. The attached addendum addresses the comments and request for additional information received from the EPA in a completeness determination letter dated May 4, 2012.

The EPA has also requested a cultural resources report and biological assessment for the project action area. Those reports are currently being prepared and will be submitted when finalized. As confirmed by the EPA, this information is not required for the completeness determination.

If you have questions or require additional information, I can be contacted at (713) 740-3925 or vdarr@petrologistics.com.

Sincerely,

Vance Darr, P.E.
Environmental Manager

PETROLOGISTICS

PL Propylene LLC
9822 La Porte Freeway
Houston, TX 77017

CC:

Mr. Mike Wilson, P.E., Director
Air Permits Division (MC 163)
Texas Commission on Environmental Quality
P.O. Box 13087
Austin, TX 78711-3087

Environmental Protection Agency, Region 6
Electronic PDF Document of Application
Submitted to:Wilson.Aimee@epamail.epa.gov

Prevention of Significant Deterioration Greenhouse Gas Permit Application For Added Combustion Sources

Addendum
(Response to May 4, 2012 Completeness Determination Letter)

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

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Zephyr Project 011377

Application Submitted February 2012
Addendum July 2012

zephyr

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FIGURES

TABLES

APPENDICES

1.0 INTRODUCTION

PL Propylene LLC (PLP) is located at 9822 La Porte Freeway, Houston, Texas 77017. In 2010, the site's Texas Commission on Environmental Quality (TCEQ) New Source Review (NSR) permit no. 18999, was amended to authorize the construction of facilities to produce propylene using a licensed propane dehydrogenation technology (Catofin®). This permit amendment application is required to 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 associated natural gas piping.

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.

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 addendum to the application originally submitted in February 2012 addresses the deficiencies noted by EPA during their completeness determination review in May 2012. See Appendix A for a copy of EPA's completeness determination letter dated May 4, 2012. Appendix B contains PLP's responses to EPA's Comments on PLP's initial application.

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

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

2.0 PROJECT SCOPE

2.1 INTRODUCTION

The PLP plant catalyst regeneration system currently consists of five combustion units and three electric blowers whose exhausts are manifolded together before passing 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 boiler to get the steam to the proper pressure and temperature for use at the PLP site. 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)

During normal regeneration operations, the combustion units ultimately 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

2.2 PROPRIETARY PROCESS COMBUSTION UNITS

The proprietary process combustion units (GT6 through GT11) will burn pipeline quality natural gas to produce the hot gases needed to regenerate the catalyst in the dehydrogenation reactors.

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 (SCR2) 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

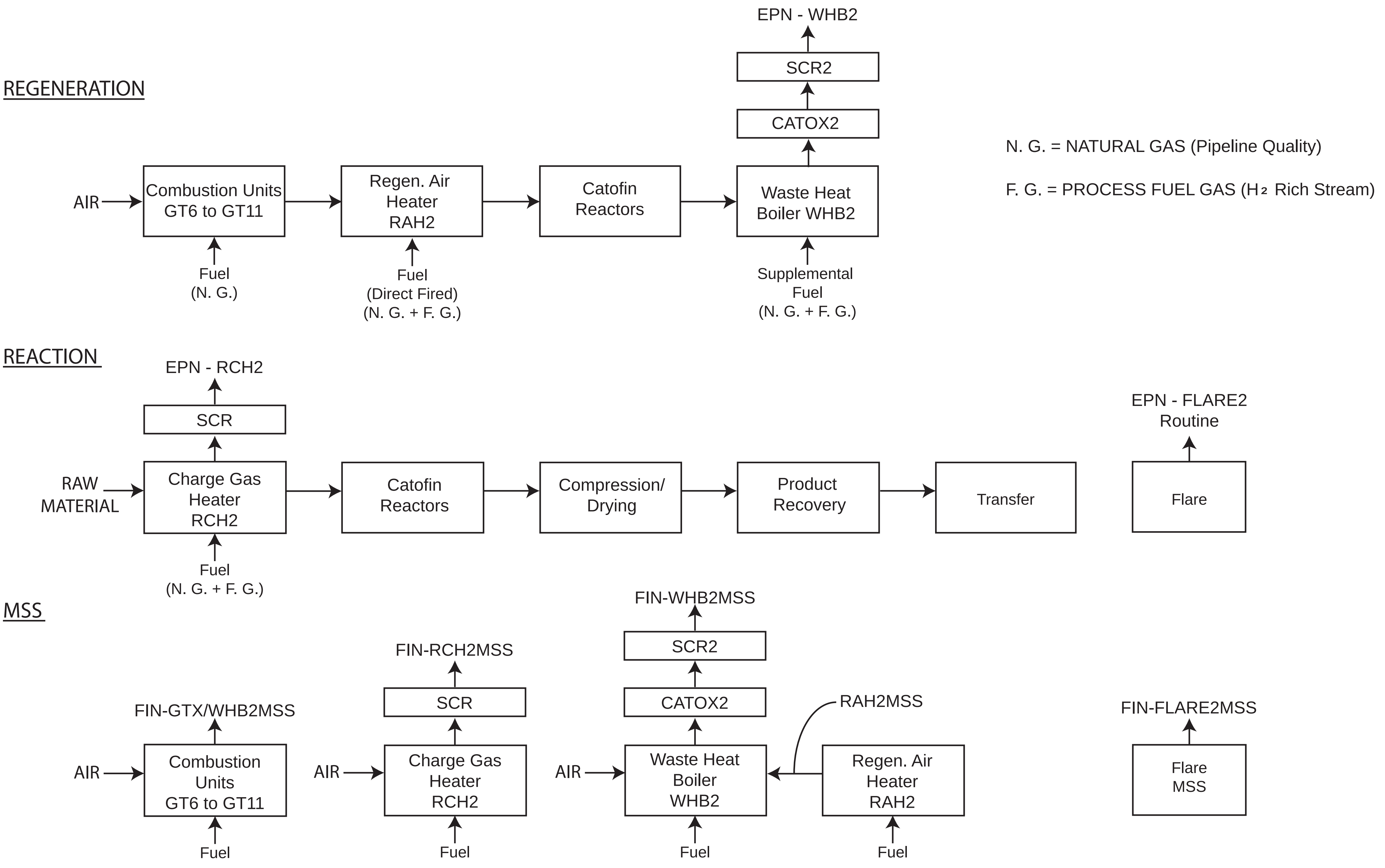
The waste heat boiler (WHB2) receives the exhaust gases from the regeneration reactors and uses the heat of the gases to produce steam. Supplemental fuel (natural gas and process fuel gas) is used to get the steam to the proper pressure and temperature for use in plant operations. The combustion gases leaving the WHB2 pass through a catalytic oxidation (CATOX2) unit to control CO and VOC emissions and a SCR2 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.

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 PLANT2) associated with these units will include emissions of methane (CH_4) and carbon dioxide (CO_2).



N. G. = NATURAL GAS (Pipeline Quality)

F. G. = PROCESS FUEL GAS (H_2 Rich Stream)

zephyr

FIGURE 2-1: PROCESS FLOW DIAGRAM

HOUSTON OLEFINS PLANT
PL PROPYLENE LLC

K:\PL Propylene LLC\011377 NSR\Graphics\PFD

Drafted By:	Reviewed By:	Project No.:	Date:
J. Knowles	E. Fessinger	011377	07/27/2012

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 Table 3-1. 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

GHG emission calculations 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 (Appendices A-2-1 through A-2-4).[3] CO_2 emissions are calculated using equation C-1:

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

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 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.[5] 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.[6]

3.3 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 is dependent on process feedstock quality and the age of the dehydrogenation catalyst and 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%

3.4 GHG EMISSIONS FROM FLARE

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:

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 multiuse flare that will be used to control emissions from routine processes, maintenance, startup, and shutdown activities (MSS), and emergency releases.

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

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

Table 3-1

7/26/2012

PL PROPYLENE LLC
GHG EMISSIONS

Emission Unit	CO2			CH4			NO2			TOTAL		
	CO2	CO2e	% Total CO2e	CH4	CO2e	% Total CO2e	NO2	CO2e	% Total CO2e			
	mtpy	mtpy		mtpy	mtpy		mtpy	mtpy		mtpy	mtpy CO2e	% CO2e
GT6	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
GT7	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
GT8	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
GT9	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
GT10	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
GT11	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
WHB2	177886.30	177886.30	17.76	3.36	70.46	5.50	0.34	104.01	17.77	177890.00	178060.77	17.75
RCH2	173241.80	173241.80	17.30	3.27	68.62	5.36	0.33	101.29	17.30	173245.40	173411.71	17.29
RAH2	92891.04	92891.04	9.28	1.75	36.79	2.87	0.18	54.31	9.28	92892.97	92982.14	9.27
PLANT2	1.63	1.63	0.000163	8.01	883.28	68.99	0	0	0	9.64	884.91	0.09
FLARE2	8.01	8.01	0.000800	0.06	0.50	0.04	3.30E-05	0.00414	0.001	8.07	8.51	0.001
TOTAL	1,001,375	1,001,375	100.00	26.95	1,280	100.00	1.93	585	100.00	1,001,404	1,003,241	100.00

Percent of total emissions, mtpy (GHG)	
CO2 =	99.997%
CH4 =	0.003%
NO2 =	0.0002%

Percent of total emissions,mtpy (CO2e)	
CO2 =	99.814%
CH4 =	0.13%
NO2 =	0.06%

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: **Jul-12**	**Permit No.:** **18999**	RN102576063
Area Name: **PL Propylene LLC**		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			**t or Air Conta**	3. Air Contaminant Emission Rate	
(A) EPN	**(B) FIN**	**(C) NAME**		(A) Pounds per Hour	(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
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

EPN = Emission Point Number
FIN = Facility Identification Number

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date: Jul-12	**Permit No.:**	**18999**	RN102576063
Area Name: PL Propylene LLC			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				3. Air Contaminant Emission Rate	
(A) EPN	**(B) FIN**	**(C) NAME**	**t or Air Contai**	(A) Pounds per Hour	(B) TPY
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
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
			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

Jul-12	**Permit No. 18999**	**Regulated Entity No.: RN102576063**
Area Nam PL Propylene LLC		**Customer Reference N 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. Bldg Ht (ft.)	**6. Ht Above Ground (ft.)**	**7. Stack Exit Data**			**8. Fugitives**		
(A) EPN	**(B) FIN**	**(C) NAME**	**Zone**	**East (Meters)**	**North (Meters)**			**(A) Diam. (ft.)**	**(B) Vel. (fps)**	**(C) Temp. (°F)**	**(A) Length (ft.)**	**(B) Width (ft.)**	**(C) Axis Degrees**
GT6	GT6/WHB2 MSS	Gas Turbine MSS	15	282400	3288023		40	2.5	250.0	1000			
GT7	GT7/WHB2 MSS	Gas Turbine MSS	15	282358	3288019		40	2.5	250.0	1000			
GT8	GT8/WHB2 MSS	Gas Turbine MSS	15	282400	3288013		40	2.5	250.0	1000			
GT9	GT9/WHB2 MSS	Gas Turbine MSS	15	282359	3288009		40	2.5	250.0	1000			
GT10	GT11/WHB2 MSS	Gas Turbine MSS	15	282400	3288004		40	2.5	250.0	1000			
GT11	GT11/WHB2 MSS	Gas Turbine MSS	15	282358	3288000		40	2.5	250.0	1000			
FLARE2	FLARE2	Flare (Routine)	15	282182	3287878		199.0	0.8		1500.0			
RCH2	RCH2	Charge Gas Heater	15	282432	3287961		132.0	8.0	50.0	400.0			
WHB2	WHB2	Waste Heat Boiler	15	282379	3287901		125.0	20.0	48.7	300.0			
PLANT2	PLANT2	LDAR Fugitives	15	282265	3287906		3			77	500	650	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 APPLICABILITY

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.[7]

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.[8] 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.

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[7] 40 C.F.R. § 52.21(b) (12)

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

4) Evaluate most effective controls and document results.
5) Select the BACT.

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[9]
2) *PSD and Title V Permitting Guidance for Greenhouse Gases*[10]
3) *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers* [11]
4) *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from The petroleum Refining Industry* [12]
5) *Energy Efficiency Improvement and Cost Saving Opportunities for the Petrochemical Industry: An ENERGY STAR® Guide for Energy and Plant Managers* [13]

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.
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.

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

[10] 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

[11] 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

[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/refineries.pdf

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

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 CGT11)

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 Catofin® 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 so 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

There are two technologies that can be used to minimize CO_2 emissions from the proprietary natural gas fired combustion units:

1) Improved combustion unit design.
2) Good combustion unit maintenance and operation practices.

5.1.2 Step 2 – Elimination of Technically Infeasible Alternatives

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

2) Recommended maintenance and operating procedures are available from the manufacturer.

5.1.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) 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.
2) 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

1) 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.
2) 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 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 certain temperature, an alarm is triggered 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 that every 500 operating hours (peak load) or 4000 hours (base load) that a detailed visual inspection be conducted to check for external leakage, drain systems pluggage, air intake system, and exhaust unit.

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 Catofin® 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

There are a number of control technologies that can be utilized to optimize the operation of the air heater and thereby reduce the amount of CO_2 formed:

1) Burner design.
2) Air heater design.
3) Burner and heater maintenance procedures.
4) Burner and heater operational procedures.
5) Use of low carbon fuel gas.

5.2.2 Step 2 – Elimination of Technically infeasible Alternatives

1) The burner supplied for the air heater is manufactured by ZEECO or equivalent. The burner is a duct burner and fires gas only with a NO_X range (lb NOX/MMBTU) to be determined by a performance test after the unit has started up. It is technically proven and commercially available.
2) The air heater is a direct-fired heater. It is designed for a natural gas heat input of 200 MMBTU/HR and is commercially available
3) Procedures for routine maintenance for the burner and heater will be supplied by the selected vendor whose experienced field personnel will train the new operating personnel.
4) Procedures for routine operation and troubleshooting of the burner and heater will be supplied by manufacturer whose experienced field personnel will train the new operating personnel.
5) The process design allows for the recovery of 90% of the total vent gases produced. The recovered fuel has a 5% to 25% hydrogen content which replaces an equivalent amount of natural gas (on a heating value basis). 15% to 30% of the recovered fuel gas is CH_4 through C4's, which would normally be flared. The overall net result is a reduction in CO_2 emissions. This recovery system and use of the recovered gases has been demonstrated in the currently existing plant.

5.2.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) Improved burner and heater design is the most effective control technology since it is a one-time upfront cost and doesn't rely on personnel following the manufacturer's recommended maintenance and operation procedures.
2) Recovering the process vent gas for use as fuel, thereby backing out an equivalent heat content amount of natural gas, is very effective in reducing CO_2 emissions.
3) 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.

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

1) As mentioned in step 3, the latest design concepts for the burner used in this project are considered to be the most effective in minimizing CO_2 formation. A heater built to strict boiler codes and well insulated will effectively minimize CO_2 formation by optimizing the efficiency of the heater system.
2) Recovering the process vent gas for use as fuel is equivalent to saving 825 MMBTU/HR for all the combustion sources in this project.
3) Trained maintenance and operating personnel are effective in maintaining peak efficiency of the heater if the manufacturer's procedures are followed.

5.2.5 Step 5 – Selection of BACT

BACT for this heater consists of use of the latest technical designs for the units, use of recovered process fuel gas, and proper maintenance following the manufacturer's recommendations to keep the units running at their peak capability to minimize CO_2 formation in the combustion process by maintaining it at its design efficiency factor of 117.3 lb CO2/MMBTU heat input. The heater is forced draft with continuous monitoring of the fire box temperature to assure that it is kept above the manufacturer's recommended operating temperature (1,100 °F). A system performance test after startup will determine the actual optimum operation temperature. In addition the burner and firebox will be physically inspected annually either with a bore-scope or visually through inspection ports .to see if there is any burner damage or unusual flame patterns which would indicate poor combustion and therefore higher CO_2 emissions. Fuel gas pressure to the heater will be monitored. An abrupt or gradual increase in fuel gas pressure is indicative of plugged burner tips which would cause improper combustion which will adversely affect the composition of the flue gas.

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 (SCR2) system for NO_X reduction unit before being exhausted to the atmosphere.

5.3.1 Step 1 - Identification of Potential Control Technologies

There are a number of technologies that can be utilized to recover the CO_2 formed by combustion of natural gas and to optimize the operation of the air heater and thereby reduce the amount of CO_2 formed:

1) Burner design.
2) Air heater design.
3) Burner and heater maintenance procedures.
4) Burner and heater operational procedures.
5) Use of low carbon fuel gas.
6) Post-combustion controls (see Section 5.7 for BACT discussion).

5.3.2 Step 2 – Elimination of Technically Infeasible Alternatives

1) The burner fires gas only and is considered to be a "low NO_X burner". It is technically proven and commercially available.
2) The feed heater is an induced draft heater. It is designed for a natural gas heat input of 373 MMBTU/HR and is commercially available.
3) Procedures for routine maintenance for the burner and heater will be supplied by the burner and heater manufacturers whose experienced field personnel will train the new operating personnel.
4) Procedures for routine operation and troubleshooting of the burner and heater will be supplied by the burner and heater manufacturers whose experienced field personnel will train the new operating personnel.
5) The process design allows for the recovery of 90% of the total vent gases produced. The recovered fuel has a 20% to 30% hydrogen content, which replaces an equivalent amount of natural gas (on a heating value basis). 40% to 55% of the recovered fuel gas is CH_4 through C4's, which would normally be flared. The overall net result is a reduction in CO_2 emissions. This recovery system and use of the recovered gases has been demonstrated in the facility's existing unit.

5.3.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) Improved burner and heater design is the most effective control technology since it is a one-time up-front cost and doesn't rely on labor intensive operations.

2) Recovering the process vent gas for use as fuel, thereby backing out an equivalent heat content amount of natural gas, is very effective in reducing CO_2 emissions.
3) Operating the units as recommended by the manufacturer can be an effective technology but only if maintenance and operating personnel follow the manufacturers' recommended procedures.

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

1) As mentioned in step 3, the latest design concepts for the burner used in this project are considered to be the most effective in minimizing CO_2 formation. A heater built to strict boiler codes and well insulated will effectively minimize CO_2 formation by optimizing the efficiency of the heater system.
2) Recovering the process vent gas for use as fuel is equivalent to saving 825 MMBTU/HR for all the combustion sources in this project.
3) Trained maintenance and operating personnel are effective in maintaining peak efficiency of the heater if the manufacturer's procedures are followed.

5.3.5 Step 5 – Selection of BACT

BACT for this heater consists of use of the latest technical designs for the units, use of recovered process fuel gas, and following recommended maintenance and operating procedures to keep the units running at their peak capability to minimize CO_2 formation in the combustion process and maintain it at its design efficiency factor of 117.3 lb CO_2/MMBTU heat input. A continuous emissions monitor (CEM) will be installed to monitor the CO_2 levels in the heater flue gas. The heater is induced draft with continuous monitoring of the fire box temperature to assure that it is kept above the manufacturer's recommended operating temperature (1,300 °F). A system performance test after startup will determine the actual optimum operation temperature. In addition, the burner and firebox will be physically inspected annually either with a bore-scope or visually through inspection ports to see if there is any burner damage or unusual flame patterns that would be indications of poor or inefficient combustion. Fuel gas pressure to the heater will be monitored. An abrupt or gradual increase in fuel gas pressure is indicative of plugged burner tips which would cause improper combustion and subsequently adversely affect the composition of the flue gas.

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 (CATOX2) for CO and VOC control and then to a selective catalyst reduction unit (SCR2) 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

There are a number of technologies that can be utilized to recover the CO_2 formed by combustion of natural gas and to optimize the operation of the air heater and thereby reduce the amount of CO_2 formed:

1) Burner design.
2) Air heater design.
3) Burner and heater maintenance procedures.
4) Burner and heater operational procedures.
5) Use of low carbon fuel gas.
6) Post-combustion controls (see section 5.7 for BACT discussion).

5.4.2 Step 2 – Elimination of Technically Infeasible Alternatives

1) The burner supplied for the waste heat boiler is a duct burner. The burner fires gas only and is considered to be a “low NO_X burner”. This design is technically proven and commercially available.
2) The boiler is a forced draft system. It is designed for a gas heat input of 383 MMBTU/HR and is commercially available.
3) Procedures for routine maintenance for the burner and heater will be supplied by the waste heat boiler and burner manufacturers whose experienced field personnel will train the new operating personnel.
4) Procedures for routine operation and troubleshooting of the burner and heater will be supplied by boiler and burner manufacturers whose experienced field personnel will train the new operating personnel.
5) The process design allows for the recovery of 90% of the total vent gases produced. The recovered fuel has a 5% to 25% hydrogen content which replaces an equivalent amount of natural gas (on a heating value basis). 30% to 75% of the recovered fuel gas is CH_4 through C4’s, which would normally be flared. The overall net result is a reduction in CO_2 emissions. This recovery system and use of the recovered gases has been demonstrated in the facility’s existing unit.

5.4.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) Improved burner and heater 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.
2) Recovering the process vent gas for use as fuel, thereby backing out an equivalent heat content amount of natural gas, is very effective in reducing CO_2 emissions.

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

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

1) As mentioned in step 3, the latest design concepts for the burner used in this project are considered to be the most effective in minimizing CO_2 formation. A heater built to strict boiler codes and well insulated will effectively minimize CO_2 formation by optimizing the efficiency of the heater system.
2) Recovering the process vent gas for use as fuel is equivalent to saving 825 MMBTU/HR for all the combustion sources in this project.
3) Properly trained maintenance and operating personnel are effective in maintaining peak efficiency of the heater if the manufacturer’s recommendations are followed.

5.4.5 Step 5 – Selection of BACT

BACT for this heater consists of use of the latest technical designs for the units, use of recovered process fuel gas, and following recommended maintenance and operating procedures to keep the units running at their peak capability and to maintain it at its design efficiency factor of 117.3 lb CO_2/MMBTU heat input. A CEM will be installed to monitor the CO_2 levels in the heater flue gas. The heater is forced draft with continuous monitoring of the fire box temperature to assure that it is kept above the manufacturer’s recommended operating level (1,100 °F). A performance test conducted after the heater has started up will determine the true optimum operating temperature. In addition, the burner and firebox will be physically inspected annually either with a bore-scope or visually through inspection ports to see if there is any burner damage or unusual flame patterns that would indicate improper combustion resulting in generation of increased levels of CO_2. Fuel gas pressure to the heater will be monitored. An abrupt or gradual increase in fuel gas pressure is indicative of plugged burner tips which would cause improper combustion and subsequently adversely affect the composition of the flue gas.

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

There are a number of ways to either reduce the VOCs going to a flare and thereby reduce the amount of CO_2 formed or reduce the formation of CO_2 by good combustion techniques. The following are the techniques investigated in this analysis:

1) Flare gas recovery.
2) Good flare design.

5.5.2 Step 2 – Elimination of Technically Infeasible Alternatives

1) The amount of gases going to a flare can be reduced by the installation of commercially available recovery systems such as refrigeration units to condense the gases and return them to the process or compressors that can take gases at atmospheric pressure and either return them to the process or to a fuel system thereby backing out natural gas. These methods are technically feasible for routine venting of process gases. However, since flares are also used for the control of emergency releases and for the control of emissions resulting from maintenance, shutdown, and startup (MSS) activities, flare gas recovery systems are only feasible for routine vent streams and cannot handle the extreme variability of flow rate and composition of the gases that might be routed to such a system.
2) Good flare design can be employed to assure good destruction of VOCs while minimizing the amount of combustion products (i.e. CO_2). Much work has been done by flare manufacturers to assure that VOCs are well controlled. Good flare design includes properly sizing the flare, installing flare pilot flame monitors, calculating the amount of steam or air necessary to assure good combustion and avoid incomplete combustion which results in unsightly smoking, monitoring flow of the gases to the flare and the steam or air used to assist combustion, and monitoring of the heating value of the gases to the flare to assure good combustion. Typically most flares are designed as elevated flares with the vented gases being combusted at the tip of the flare. Consequently, flare turn-down (i.e. vent gas flows well below the design flow) is an issue. This project will utilize an open ground flare (OGF). An OGF allows for the destruction of elevated quantities of emergency gas discharge with smokeless functionality at any instant flow rate. Such efficiencies minimize CO_2 formation.

5.5.3 Step 3 – Ranking of Remaining Technologies Based on Effectiveness

1) Flare gas recovery is very effective but only for routine (steady flow rate and composition) gas streams.
2) Good flare design, including proper instrumentation (pilot flame, flared gas flow, assist gas flow, heating value, and velocity) will minimize CO_2 emissions by reducing the amount of natural gas required for proper VOC destruction.

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

1) Good flare design is the most effective means to minimize CO_2 emissions.
2) Flare gas recovery is effective, but only for a portion of the gases going to the flare at any given time.

5.5.5 Step 5 – Selection of BACT

1) Flare gas recovery will be utilized for the routine gas flows of up to 27,000 lb/hr. The system will recover 25,000 lb/hr, which is the most the plant can effectively utilize. While the recovery system could be designed to take flows above 27,000 lb/hr, any additional gas recovered would have to be flared since it is surplus over and above what the plant could utilize.
2) Good flare design (i.e. an open ground level flare) is technically achievable and meets the criteria to be considered BACT for this project. The flare will be designed and monitored by instrumentation to meet the applicable requirements of 40 CFR §60.18 (pilots, adequate heating value, and maximum flare gas velocity) and 30 TAC §115.720 (Vent Gas Control for Highly Reactive Volatile Organic Substances).

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) The use of an instrumented monitoring system such as LDAR is technically feasible but quite time consuming (Method 21 requires that the instrument be held a certain distance from the component and for a specified period of time). Only one component can be monitored at a time.
3) 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.
4) AVO monitoring is very effective but only for leaks big enough to be seen or heard, or for leaks of chemicals with low odor thresholds.
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 a semi-annual basis coupled with 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 POST-COMBUSTION CONTROLS

5.7.1 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 recoveredCO_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 CO2 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 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…[14].
>
> 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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[14] 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.

5.7.1 Step 2: Eliminate Technically Infeasible Options

5.7.1.1 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”[15] 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[16]. Officials said the plant

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[15] 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

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

will demonstrate the viability of capturing and reusing carbon dioxide as a profitable business-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.

5.7.1.2 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"[17]. 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)[18] 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

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

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

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

5.7.1.3 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)[19]. 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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[19] SECARB Press Release; http://www.sseb.org/secarb.php

5.7.2 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.

5.7.3 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 $410 million. Amortized capital costs are expected to be $41 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 993,000 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[20] 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.

5.7.4 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.

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[20] 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

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 CO2	Pollutant Methane	Control Method
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

Rev. 7-19-12

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]	$11,049,626
Annual Chemical Usage (solvent, caustic, activated carbon) [2]	$2,671,338
Annual Waste Disposal (reclaimer, spent carbon) [PLP]	$883,087

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 STORAGE

Annual Operating Cost	$3,973,892
Liability Trust Fund [4]	*$5,000,000*
Annual Fund Cost [4]	$500,000
Total Annual Storage Cost	*$4,473,892*

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 SOURCES (PSD APPLICATION)

CU-6	102,395.92	tpy
CU-7	102,395.92	tpy
CU-8	102,395.92	tpy
CU-9	102,395.92	tpy
CU-10	102,395.92	tpy
CU-11	102,395.92	tpy
CGH2	190,968.39	tpy
RAH2	102,395.92	tpy
WHB2	196,088.18	tpy
Flare (routine)	8.86	tpy
Flare (MSS)	21.91	tpy
Total CO2 Emissions	1,103,858.78	tpy
	3024	tpd

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	**81,203,620**
CO2 Reduction (ton CO2/year), tpy	**993,473**
Annual Control Cost, dollars/ton CO2/year	**$82**

RECOVERY FACTOR

Equipment Life,years	20
Interest Rate	8%
Capital Recovery Factor (CRF)	0.101852209

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

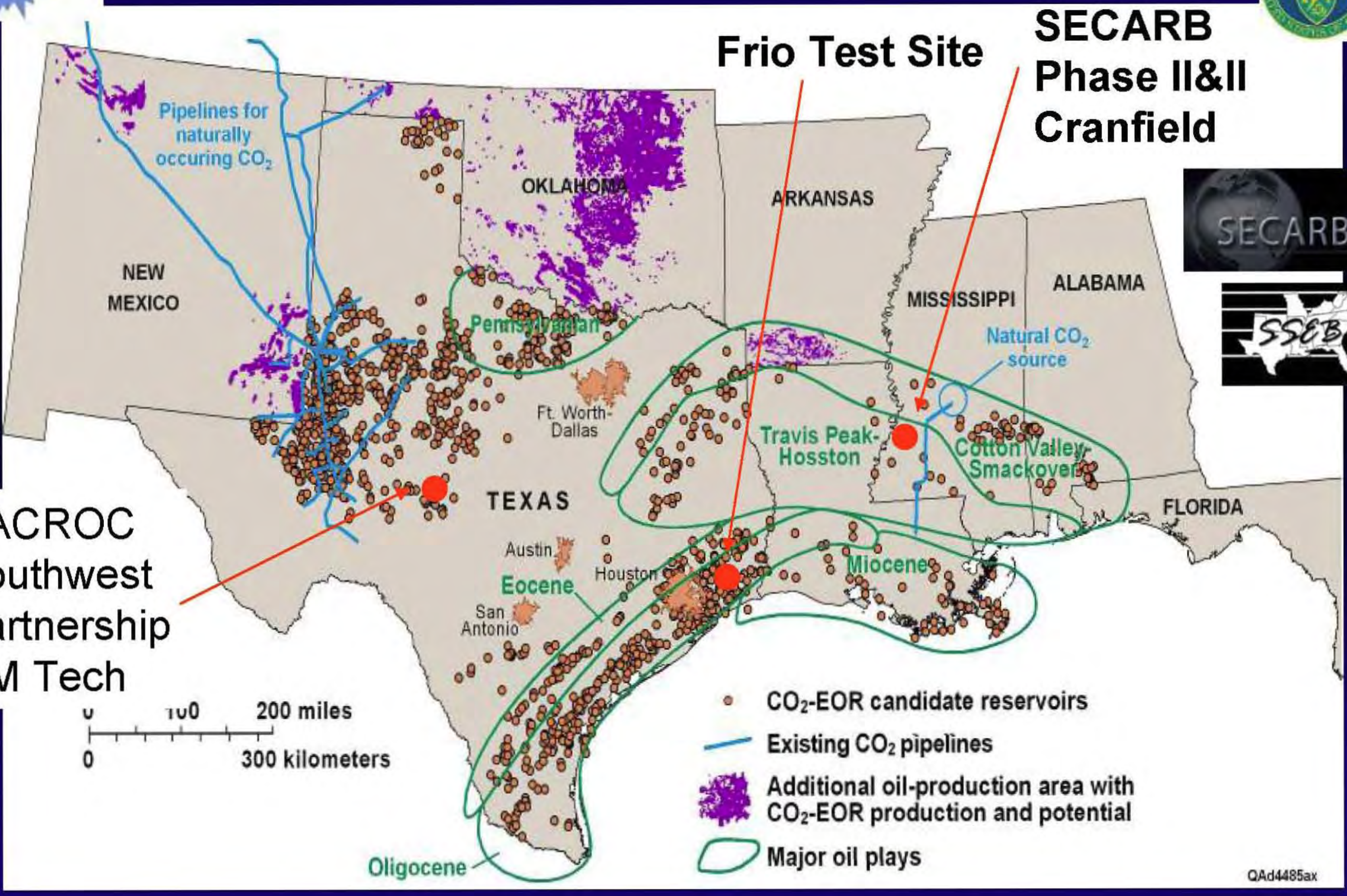
Table 5-3

PL Propylene LLC
GHG BACT MONITORING REQUIREMENTS

Rev. 7-24-12

Emission Unit	Monitored Parameter	Frequency	Limit
Process Combustion Units (CU6-CU11)	Differential temperature across burners	Continuous	+/- 158 °F
	Visually inspect burners	Shutdown every 4000 operating hours	Bore scope looking for hot spots on the firing cans
	Bore scope inspection of blades		No scoring or blade damage
	Visual inspection for external leakage, drain system pluggage, air intake, and exhaust unit	Once/day	No leakage, pluggage, fouling
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 °F
Fired Heater (RCH2)	Fire box temperature	Continuous	> 1,300 °F
	Visual inspection of burner and firebox	Annually	No burner damage or unusual flame patterns
	Fuel gas pressure	Continuous	< 70 °F
Waste Heat Boiler (WHB2)	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 °F
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

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.*[21]

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.*[22]

6.3 ADDITIONAL IMPACTS ANALYSIS

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

> *Furthermore, consistent with EPA's statement in the Tailoring Rule, EPA believes it is not necessary for applicants or permitting authorities to assess impacts from GHGs in the context of the additional impacts analysis or Class I area provisions of the PSD regulations for the following policy reasons. Although it is clear that GHG emissions contribute to global warming and other climate changes that result in impacts on the environment, including impacts on Class I areas and*

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

[22] *Id.* At 49

soils and vegetation due to the global scope of the problem, climate change modeling and evaluations of risks and impacts of GHG emissions is typically conducted for changes in emissions orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible with current climate change modeling. Given these considerations, GHG emissions would serve as the more appropriate and credible proxy for assessing the impact of a given facility. Thus, EPA believes that the most practical way to address the considerations reflected in the Class I area and additional impacts analysis is to focus on reducing GHG emissions to the maximum extent. In light of these analytical challenges, compliance with the BACT analysis is the best technique that can be employed at present to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHGs.[23]

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[23] *Id.*

Appendix A

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

MAY 04 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 Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) permit application dated February 3, 2012 and received in our office on February 7, 2012. After an initial review of your application we have determined that additional information is necessary in order to begin the processing of the permit. Enclosed is a list of the information required.

Upon the receipt of this information, the Environmental Protection Agency (EPA) will begin the process of developing a Statement of Basis and rationale for the terms and conditions for a draft PSD permit. As we develop our preliminary determination and draft permit, it may be necessary for the EPA to request additional clarifying or supporting information. Supplemental information on one or more parts of the application may be required before we can propose a draft permit. If the supporting information substantially changes the original scope of the permit application, an amendment or new application may be required.

While not required for the completeness determination, the EPA may not issue a permit until it has been established that the issuance of the permit will have no impact on endangered species pursuant to Section 7 of the Endangered Species Act. In addition, the EPA must complete a consultation in accordance with Section 106 of the National Historic Preservation Act. To expedite these consultations, the EPA requests that the permit applicants provide a biological assessment and cultural resources report covering the project and action area. We request that you submit this information as early as possible, so that the EPA may issue a permit at the earliest possible time, and within the timeframes required by statute.

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,

Thomas Diggs for

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

Enclosure

EPA Comments on PL Propylene LLC Greenhouse Gas Permit Application Application dated February 7, 2012

General

1. Please provide a copy of the corresponding permit application submitted to TCEQ for non-GHG pollutants for this project.

2. EPA is not aware of the quantity of non-GHG emissions from this project and whether it will be subject to PSD review by TCEQ. If the project is subject to PSD solely because of its GHG emissions and one or more of the non-GHG pollutants are emitted at or above the applicable PSD significant levels – as defined in 40 CFR 52.21(b)(23) – and below the applicable 100 or 250 TPY major source threshold, then Region 6 will issue the permit for not only GHGs, but for the other regulated NSR pollutant(s) emitted in a significant amount. Please submit supplemental information to substantiate that no other regulated NSR pollutants will increase in a significant amount. If any increases of non-GHGs will be significant, you must submit the applicability calculations with a five-step top down BACT analyses for the pollutant(s). You must also consult with us on the preparation and submission of air quality analyses to satisfy the requirements of 52.21(k), (m), (o) and (p), as may be applicable.

3. The application does not provide the production volume for the proposed modifications to the facility. How much propylene will the facility produce annually?

4. The application offers no recommendations for monitoring, recordkeeping, and reporting for the CO_2 emissions. Does PL Propylene have a preferred monitoring method for the proprietary combustion units, charge gas heater, regeneration heater, waste heat boiler, regenerative thermal oxidizer, and flare?

5. Will the process fuel gas be monitored using online instrumentation to determine the composition and the high heat value?

BACT Analysis

6. The application provides a five-step BACT analysis for Carbon Capture and Sequestration (CCS) and concludes that the use of this technology is technically infeasible. A general cost analysis is provided. Please supplement the cost analysis with details indicating the equipment needed to implement CCS, the costs of such equipment, the size and length of pipeline needed for transport, and provide site specific costs versus

a range of approximate costs. Also, we are requesting a comparison of the cost of CCS to the current project's annualized cost.

7. The current BACT analysis does not appear to provide adequate information in the five-step BACT analysis for the proprietary combustion units, charge gas heater, regeneration heater, waste heat boiler, regenerative thermal oxidizer, and flare. Step 2 does not provide detailed information on the energy efficiency measures. In Step 3, the applicant should provide information on control efficiency, expected emission rate, and expected emission reductions. The applicant should provide comparative benchmark information to indicating other similar industry operating or designed units and compare the design efficiency of this process to other similar or alike processes. The applicant should then use this information to rank the available control technologies. A comparison of equipment energy efficiencies is necessary to evaluate the energy efficiency of the proposed equipment and possible control technologies. This information should also detail the basis for your BACT proposal in determining BACT limits for the emission units for which these technologies are applied in Step 5. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. For example, the energy efficiency of the heaters should be tied to a BACT limit. BACT limits for GHG emission units should be output based limits preferably associated with the efficiency of individual emission units. Please propose short-term emission limitations or efficiency based limits for all emission sources. For the emission sources where this is not feasible, please propose an operating work practice standard. Please provide detailed information that substantiates any reasons for infeasibility of a numerical limit. PL Propylene should supplement the BACT analysis to provide all necessary information required in Steps 2, 3, and 4 of the five-step BACT analysis.

8. The BACT analysis provided does not evaluate the natural gas piping and fugitive emissions. Please provide a five-step BACT analysis for these emission units including the use of a leak detection and repair (LDAR) program.

Appendix A

9. The Table identified as "Appendix A-1 Summary" gives the firing rate for the combustion units. Are these values an annual average firing rate or a maximum firing rate?

10. The "Appendix A-1 Summary" Table also shows the proprietary combustion units, regeneration air heater, and waste heat boiler to have the same EPN. Do these units vent to a common stack?

Appendix B

APPENDIX B

EPA Comments on PL Propylene LLC
Greenhouse Gas Permit Application
Application dated February 7, 2012

1. Please provide a copy of the corresponding permit application submitted to TCEQ for non-GHG pollutants for this project.

   The NSR application was submitted to TCEQ on June 8, 2012 and a copy of the non-confidential sections was sent to Ms. Aimee Wilson and R6airPermits@EPA.gov at EPA Region 6 June 8, 2012.

2. EPA is not aware of the quantity of non-GHG emissions from this project and whether it will be subject to PSD review by TCEQ. If the project is subject to PSD solely because of its GHG emissions and one or more of the non-GHG pollutants are emitted at or above the applicable PSD significant levels — as defined in 40 CFR 52.21(b)(23) — and below the applicable 100 or 250 TPY major source threshold, then Region 6 will issue the permit for not only GHGs, but for the other regulated NSR pollutant(s) emitted in a significant amount. Please submit supplemental information to substantiate that no other regulated NSR pollutants will increase in a significant amount. If any increases of non-GHGs will be significant, you must submit the applicability calculations with a five-step top down BACT analyses for the pollutant(s). You must also consult with us on the preparation and submission of air quality analyses to satisfy the requirements of 52.21(k), (m), (o) and (p), as may be applicable.

   TCEQ Netting Table 1F shows that Federal New Source Review (FNSR) for the non-GHG pollutants is not applicable for this project. This Table is found in Appendix B of the TCEQ NSR application.

3. The application does not provide the production volume for the proposed modifications to the facility. How much propylene will the facility produce annually?

   1.6 million pounds per year.

4. The application offers no recommendations for monitoring, recordkeeping, and reporting for the CO_2 emissions. Does PL Propylene have a preferred monitoring method for the proprietary combustion units, charge gas heater, regeneration heater, waste heat boiler, regenerative thermal oxidizer, and flare?

   Recommendations for monitoring are covered on Table 5-3. Records of monitored parameters will be kept for a period of five years which is consistent with the requirements for federal standards. Deviations will be reported on a semi-annual basis which is also consistent with other federal requirements. There is no regenerative thermal oxidizer associated with this project. The only routine emission points will be the charge gas heater, the waste heat boiler, and the flare. The proprietary combustion units and regen air heater routinely exhaust to the

waste heat boiler. Only during maintenance, startup, and shutdown (MSS) periods do they vent directly to the atmosphere and then only for a very short period of time such that monitors are inappropriate. The charge gas heater, waste heat boiler, and flare will have systems to monitor and keep records of CO_2 emissions during routine operations. Refer to Figure 2-1 of Addendum.

5. Will the process fuel gas be monitored using online instrumentation to determine the composition and the high heat value?

   Samples will be taken on a periodic basis and analyzed to determine composition and high heat value.

6. The application provides a five-step BACT analysis for Carbon Capture and Sequestration (CCS) and concludes that the use of this technology is technically infeasible. A general cost analysis is provided. Please supplement the cost analysis with details indicating the equipment needed to implement CCS, the costs of such equipment, the size and length of pipeline needed for transport, and provide site specific costs versus a range of approximate costs. Also, we are requesting a comparison of the cost of.CCS to the current project's annualized cost.

   Refer to Section 5.7 of Addendum.

7. The current BACT analysis does not appear to provide adequate information in the five-step BACT analysis for the proprietary combustion units, charge gas heater, regeneration heater, waste heat boiler, regenerative thermal oxidizer, and flare. Step 2 does not provide detailed information on the energy efficiency measures. In Step 3, the applicant should provide information on control efficiency, expected emission rate, and expected emission reductions. The applicant should provide comparative benchmark information to indicating other similar industry operating or designed units and compare the design efficiency of this process to other similar or alike processes. The applicant should then use this information to rank the available control technologies. A comparison of equipment energy efficiencies is necessary to evaluate the energy efficiency of the proposed equipment and possible control technologies. This information should also detail the basis for your BACT proposal in determining BACT limits for the emission units for which these technologies are applied in Step 5. Where appropriate, net output-based standards provide a direct measure of the energy efficiency of an operation's emission-reducing efforts. For example, the energy efficiency of the heaters should be tied to a BACT limit. BACT limits for GHG emission units should be output based limits preferably associated with the efficiency of individual emission units. Please propose short-term emission limitations or efficiency based limits for all emission sources. For the emission sources where this is not feasible, please propose an operating work practice standard. Please provide detailed information that substantiates any reasons for infeasibility of a numerical limit. PL Propylene should supplement the BACT analysis to provide all necessary information required in Steps 2, 3, and 4 of the five-step BACT analysis.

   Refer to Section 5.0 of Addendum.

8. The BACT analysis provided does not evaluate the natural gas piping and fugitive emissions. Please provide a five-step BACT analysis for these emission units including the use of a leak detection and repair (LDAR) program.

   Refer to Section 5.6 of Addendum.

9. The Table identified as "Appendix A-1 Summary" gives the firing rate for the combustion units. Are these values an annual average firing rate or a maximum firing rate?

   The firing rate for the combustion units in this application is the design maximum heat rate for 8688 hours per year. Maintenance, Startup, and Shutdown (MSS) situations are assumed to total 72 hours per year.

10. The "Appendix A-1 Summary" Table also shows the proprietary combustion units, regeneration air heater, and waste heat boiler to have the same EPN. Do these units vent to a common stack?

    During normal operations there is only one emission point. The exhaust from the proprietary combustion units first passes through the regeneration air heater and then through the reactors. The reactors' hot exhaust gases then go through the waste heat boiler to generate steam utilizing the heat content of the gases. This is shown on Figure 2-1 of Addendum.