Formosa Plastics

Formosa Plastics Corporation, Texas
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Point Comfort, TX 77978
Telephone: 361-987-7000
Fax: 361-987-2363

May 20, 2013

Mr. David Garcia
Acting Director, Multimedia
Planning and Permitting Division
U.S. EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

RE: EPA Request for Information & Revised Application
Greenhouse Gas Permit Application
Formosa Plastics Corporation, Texas
2012 Expansion Project: Olefins Expansion
Point Comfort, Calhoun County, Texas

Dear Mr. Garcia:

This letter is in response to your letter dated April 9, 2013, requesting supplemental information related to FPC TX's Greenhouse Gas (GHG) permit application for the Olefins Expansion. The attachment to this letter provides the supplemental information you have requested. Please note that responses for three of the questions will be provided at a later date. FPC TX is still gathering vendor information for the responses.

In addition, as discussed with Melanie Magee, a revised Olefins Expansion GHG PSD permit application is being provided with this transmittal. The revised application incorporates the following changes related to a revised Olefins 3 plant design with approximately 50% more throughput than was represented in the initial permit application:

- quantity of cracking furnaces increased to 14 total (note with slightly lower firing rate per furnace)
- Olefins 3 plant fuel gas composition update
- increased total annual frequency of furnace decoking events
- increased quantity of fugitive piping components
- increased process equipment sizes and associated MSS emissions
- updated elevated flare waste gas flow rates and represent new two stage flare design
- increased MAPD regeneration gas volume during regeneration event

The responses to your supplemental information request (enclosed) have been addressed in relation to the updated Olefins 3 plant design. Notably, the updated block flow diagrams provided in the revised permit application reflect the design changes detailed above.

No changes are being made to the other two permit applications associated with the 2012 Expansion Project: the Gas Turbines and LDPE plant. An updated Olefins Expansion PSD application for criteria pollutant emissions will be submitted to the Texas Commission on Environmental Quality (TCEQ).

Also, as it relates to the Biological Assessment and Cultural Resources Reports, FPC TX has performed a preliminary biological assessment analysis. FPC TX continues to work on finalizing the reports as required for EPA to issue a final GHG permit. The Biological Assessment and Cultural Resources Reports will be submitted promptly.

Should you have any questions regarding this application, please contact me at tammyl@fdde.fpcusa.com, or 302-836-2241, or Ms. Karen Olson of Zephyr Environmental Corporation, at kolson@zephyrenv.com or 512-879-6618.

Sincerely,

Tammy G Lasater

Tammy G. Lasater

Enclosure

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Mr. David Garcia
Planning and Permitting Division
US EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

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Mr. David Garcia
Planning and Permitting Division
US EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

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Fron **Expéditeur:**

Zephyr Environmental Corporation
2600 Via Fortuna, Suite 450
Austin, Texas 78746

Mr. David Garcia
Planning and Permitting Division
US EPA Region 6, 6PD
1445 Ross Avenue, Suite 1200
Dallas, TX 75202-2733

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Attachment

The following is provided in response to the information request in EPA letter dated April 9, 2013. Each request for information is repeated below in bold italics followed by FPC TX response and supplemental information. To clarify the responses when responses are required for multiple sub-questions contained in EPA question, those sub-questions have been organized into the bullets below and responded to individually.

1. ***The process description should closely follow the process diagram that is provided and identify all emission points that emit GHG emissions or have the potential to emit. Also, include non-GHG sources, but please identify as such, if it is an integral part of process and feeds a GHG source. It is suggested that additional pages be created and provided to EPA to represent the process to avoid overcrowding and confusion. Please supplement the Olefins 3 and the PDH Plant process flow diagram with the following information:***

Olefins 3 Unit

A. A representation of all nine cracking furnaces along with the emission point identification numbers.

FPC TX Response: All cracking furnaces (now fourteen total) are shown on sheet BFD-01 of the revised Olefins 3 process flow diagram (see revised permit application).

B. The heat recovery that is mentioned throughout the process description should be included on the process flow diagram. This includes, but is not limited to, ethane feed (stream 1) combined with recycle ethane (stream 1R) is superheated with quench water prior to the saturator, ethane feed from saturator is superheated in a heat exchanger, feed stream to furnace is preheated in convection section, product stream (cracked gas) from the furnace radiant coils (stream 3) routed through heat exchangers where heat is recovered by boiler feed water to produce superheated high pressure steam, the vapor (stream 8) from the charge gas driers is cooled (by propylene refrigerant) before entering the deethanizer, and the deethanizer column is heated with recovered energy from low pressure steam.

FPC TX Response: These streams are now shown in more detail on sheets BFD-01 and BFD-02 of the revised Olefins 3 process flow diagram (see revised permit application).

C. On page 19 of the application, a description of the process water stripper is summarized; therefore the process water stripper should be included on the

process flow diagram and clearly indicate the closed-loop water treatment of the process water that is used to cool the cracked gases in the quench tower.

FPC TX Response: The process water stripper and associated closed-loop water treatment stream are shown on sheet BFD-01 of the revised Olefins 3 process flow diagram (see revised permit application).

D. On page 20 of the application, it is stated that the caustic blowdown from the caustic/water wash tower is routed to a collection tank. Since it is possible that the blowdown could possibly contain hydrocarbons, this collection tank is vented to a set of carbon canisters. Please supplement the process flow diagram to include the carbon canisters. What will be the compliance strategy for the canisters?

FPC TX Response: The carbon canisters are not GHG emission sources and have been added to the process flow diagram on sheet BFD-02 (see revised permit application). Non-GHGs pollutants (hydrocarbons) from the carbon canisters are being authorized in the TCEQ permit application.

E. The process description states that hydrogen is recovered in the pressure swing absorption system (PSA), but it is not included on the process flow diagram. Please supplement the diagram to include it along with the emission point identification number for the GHG source, if appropriate, or identify it as a non-GHG emission source.

FPC TX Response: The PSA is not an emission source (GHG or non-GHGs). Any process gases from this unit are recycled to the fuel gas system. The PSA has been added to sheet BFD-03 of the revised Olefins 3 process flow diagram (see revised permit application).

F. On page 22 of the application, the process description states that the fuel gas is a mixture of hydrogen-rich gas from the dryer regeneration system (deethanizer overhead), methane-rich off gas from the chilling train (demethanizer overhead), PSA off-gas and natural gas from outside battery limits (OSBL). The process flow diagram doesn't depict the combining of these streams to produce the fuel gas fed to the furnaces and steam boilers. Please supplement the process flow diagram to indicate these streams along with the emission point identification number for the GHG source, if appropriate, or identify it as a non-GHG emission source.

FPC TX Response: The fuel gas mixing drum is not an emission source of GHGs or non-GHGs. The fugitive piping components associated with the mixing drum are GHG and non-GHG emission sources which have been identified and accounted for in the permit application. The fuel gas mixing drum has been added to sheet BFD-03 of the revised Olefins 3 PFD (see revised permit application).

G. Please provide a process flow diagram of the decoking system along with the emission point identification number for the GHG source. The process diagram of the system can be depicted separately to avoid overcrowding.

FPC TX Response: The decoking system details are shown on the OL3 Heater Detail sheet of the revised process flow diagram (see revised permit application).

PDH Unit

A. Please include all four PDH reactors and Steam boilers along with the emission point identification numbers.

FPC TX Response: All four steam boilers are shown on sheet BFD-04 with emission point numbers of the revised flow diagram. All four PDH reactors are shown with emission point numbers on sheet BFD-05 of the revised flow diagram (see revised permit application).

B. Please represent the heat recovery from the reactors that is used to vaporize the propane feed to the depropanizer tower on the process flow diagram.

FPC TX Response: The propane feed preheat exchanger is shown on sheet BFD-06 of the revised flow diagram (see revised permit application).

C. On page 24 of the application, the process description states that the solvent flash drum bottoms are routed to the solvent system stripper for processing and reuse. Please supplement the process flow diagram to include this stripper along with the emission point identification, if appropriate, or identify if it has a non-GHG emission source.

FPC TX Response: The solvent stripper is shown on sheet BFD-06 of the revised flow diagram. The stripper overheads are recycled to the fuel gas knockout drum (shown on sheet BFD-05); therefore, this process vessel is not a point source of air emissions.

D. On page 25 of the application, the process description states that the mechanical energy recovery that is available at the coupling of the expander is used to generate electrical power that is charged to the electrical grid. Also, the cooling down of the expanded gas is supplying the cryogenic energy required in the cold boxes. If possible, please supplement process flow diagram to depict this energy recovery.

FPC TX Response: The expander and associated power generator that are used to generate electrical power that is charged to the plant's grid are shown on sheet BFD-07 of the revised flow diagram (see revised permit application).

E. On page 26 of the application, the process description summarizes the operation of the process condensate stripper. It is not clear from the process flow diagram the placement of this equipment in the PDH process and what feed streams are routed to the stripper and where the exit streams are routed. Please supplement process flow diagram with this information.

FPC TX Response: The process condensate stripper and its feed and exit streams are shown on sheet BFD-06 of the revised flow diagram (see revised permit application).

2. Beginning on page 27 of the permit application in the section entitled "Overall Energy-Efficient Design Philosophy", it is stated that FPC TX is incorporating several design strategies that will provide operating cost savings and the benefit of minimizing emissions of GHG throughout the plant. In this section there is a summary of the equipment selection and design attributes that include, but not limited to, the following:

- ***energy saving motors on applicable compressors,***
- ***capacity control will be installed to reduce electric energy consumption,***
- ***variable speed for blowers, pumps and compressors,***
- ***use of cold box heat exchangers instead of shell and tube exchangers,***
- ***Olefins 3 plant is designed to maximize cooling from process off-gas streams to minimize***
- ***refrigerant requirements,***
- ***Olefins 3 plant is designed to operate at lower pressure to allow easier separation of methane, which is estimated to reduce up to 10% required power for the binary compressor, requiring less refrigeration, and***
- ***Ethylene fractionator's lower-reflux design.***

Please provide supplemental technical benchmark data that compares the design selections to be employed to a similar or existing source in the industry. If possible, please provide the technical resources used to evaluate the design decisions and to support the assertions made in this section. If technical benchmark data is not available, then please provide information detailing or projecting the potential efficiency gains that are expected utilizing these design strategies. Please include the basis for the rationale and supporting calculations and resources for this information.

FPC TX is still in the process of discussion with vendors to determine what benchmark data is available; therefore, FPC TX needs more time to assemble information to respond to this question. Response to this question will be provided in a subsequent submittal.

3. ***Please provide a representation of the cooling towers for both the Olefins 3 and PDH on the process flow diagram.***

    - ***Will the cooling towers be a possible GHG emission source?***
    - ***Are there heat exchangers in either process that if a leak occurs, would allow GHG emission into the cooling water system? If so please include the emission point identification number and emission calculations. Typically CO2 emissions are associated with combustion pollutants and CH4 pollutant is associated with VOC pollutants, therefore if FPC TX feels that such streams do not have GHG pollutants an explanation is required.***

<u>FPC TX Response</u>: No GHG emissions (i.e., methane, CO_2) from the Olefins 3 cooling tower are expected to occur. When considering leaks from process equipment contacting cooling water, GHGs (i.e., methane) are not expected to be present.

The PDH unit has approximately two dozen process streams that are routed through heat exchangers which could potentially result in leaks to cooling water which is circulated to the cooling tower. Only four of those streams have the potential to contain small concentrations of GHGs. Since the concentrations of GHGs in these process streams is very low and very few streams contain GHGs, the potential for GHG leaks into the cooling water and associated GHG emissions from the PDH cooing tower is extremely low. Therefore the PDH cooling tower is not considered a GHG emission source.

4. ***On page 19 of the permit application, it states that the quench tower overhead vapors (5) are compressed in a steam turbine-driven centrifugal process gas compressor.***
    - ***Is the steam turbine driven compressor a GHG emission source? If so, please provide supplemental information to the BACT analysis.***
        - ***If not, is the steam that is used the result of heat recovery in the furnace area? Please provide supplemental information to process description and process flow diagram.***

<u>FPC TX Response</u>: The steam turbine driven compressor is not a GHG emission source. The steam turbine is a result of heat recovery in the cracking furnace; energy supplied to the compressor is coming from steam that has been produced by the furnace. The process for steam production from furnace heat recovery is shown in the OL3 Heater Detail sheet of the revised Olefins 3 flow diagram.

5. ***On page 46 of the permit application, it states that "high efficiency burners, designed for optimum combustion of the hydrogen-rich fuel gas, will be installed in the firebox on both sides of the radiant tubes." Please provide any benchmark comparison for similarly designed burners that have been permitted by air permitting authorities nationwide.***

   FPC TX is still in the process of discussion with vendors to determine what benchmark data is available; therefore, FPC TX needs more time to assemble information to respond to this question. Response to this question will be provided in a subsequent submittal.

6. ***Please provide supporting calculations, technical information and a basis for the rationale used to calculate the energy that will be recovered from the "Energy Efficient Design Elements" proposed for the cracking furnace on page 48 of the permit application.***

   FPC TX is still in the process of discussion with vendors to determine what benchmark data is available; therefore, FPC TX needs more time to assemble information to respond to this question. Response to this question will be provided in a subsequent submittal.

7. ***On page 56 of the permit application, it is stated that there aren't any applicable technologies for controlling GHG emissions from the MAPD regeneration vent. The MAPD regeneration vent's C02e emissions (estimated at less than 30 tons per year) represent less than .001% of the project's GHG emissions; therefore, this source is an inherently low-emitting GHG emission source. Being mindful of EPA's PSD and Title V Permitting Guidance for GHG dated March, 2011 on page 17, which states if the permitting authority determines that technical or economic limitations on the application of a measurement methodology would make a numerical emissions standard infeasible for one or more pollutants, it may establish design, equipment, work practices or operational standards to satisfy the BACT requirement. Were work practices or operational standards evaluated? Please provide supplemental data that details the work practices and operational standards that FPC TX is proposing to put into place for the MAPD that are practically enforceable.***

   <u>FPC TX Response</u>: FPC TX has evaluated work and operational practices and will follow an operating procedure (SOP) currently used for a similar unit during periods of MAPD catalyst regeneration. The SOP will be created and maintained at the site prior to the unit commencing operation and will dictate the length of regeneration period required.

   FPC TX will meet BACT for the MAPD unit regeneration vent by following the SOP during regeneration periods; however, FPC TX also understands that EPA has authorized GHG emissions from decoking operations for ethylene cracking furnaces (an intermittent activity/source) in several permits without this requirement. Examples of issued GHG permit which include intermittent process emission sources without permit limits other than mass emission rates and annual frequency of events include the following:

- BASF Fina Petrochemicals LP. Permit no. PSD-TX-903-GHG
- Chevron Phillips Chemical Company, LP. Permit no. PSD-TX-748-GHG
- Equistar Chemicals, LP. Permit no. PSD-TX-752-GHG

In these issued GHG permits, compliance with mass GHG emission rates and limitation of the annual frequency decoking events was sufficient for practical enforceability. Therefore, FPC TX requests a similar permit limit for MAPD regeneration (i.e., mass emission limit and annual frequency limitation).

8. ***On page 69 of the permit application, it states that FPC TX is designing the Olefins 3 plant and PDH unit with fuel gas systems which will provide beneficial reuse of hydrocarbon-containing streams that would otherwise be routed to a flare for control. In fact, as explained on page 29, "the PDH unit fuel gas system will be used as the primary fuel in all of the unit's large fired sources (reactors); totaling approximately 600 MMBtu/hr of combustion equipment. ... Depending on the propane feed composition even an export of fuel gas for use as fuel in other plants is possible." If possible, please quantify the amount of fuel gas that is anticipated to be exported to other plants?***

The PDH unit is estimated to have the design capability to export as much as 6,500 lb/hr[1] of fuel gas to other plants; however, during periods of PDH startup, fuel gas production will be limited and no fuel gas export would be expected during this operating mode.

9. ***On page 75 of the permit application, FPC TX proposes to use weekly AVO monitoring. Please provide supplemental data that discusses the details of what this program will involve. What is the proposed compliance strategy including recordkeeping, schedule, and the protocol for equipment repairs? Is there a TCEQ LDAR method that FPC TX prefers to use? Please provide supplemental data that includes the basis for utilizing this preferred method versus other.***

FPC TX Response: The GHG fugitive emission sources in this plant will be in natural gas service. FPC TX is proposing:

- To implement an Audio Visual and Olfactory (AVO) monitoring program for equipment in natural gas and fuel gas service.
    - To perform the AVO monitoring on a weekly basis

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[1] This rate is estimated for purposes of providing an understanding of the process design and is not intended to be taken as a permit limitation or enforceable representation.

  - To maintain a written log of weekly inspections identifying the operating area inspected, the date inspected, the fuel gas and natural gas equipment inspected (valves, lines, flanges, etc), whether any leaks were identified by visual, audible or olfactory inspections, and corrective actions/repairs taken
- For leaks identified, immediately of detection of the leak, plant personnel will take the following action:
  - Tag the leaking equipment
  - Commence repair or replacement of the leaking component
- AVO is a more appropriate monitoring method for natural gas components in this plant as explained in the permit application and below:
  - Monitoring can be done more frequently so leaks can be detected more quickly than with the TCEQ 28 series of Method 21 based LDAR program
  - The total estimated GHG fugitive emissions from this plant are small (<0.03% of total mass and <0.5% of the total CO_2e)

REVISED GREENHOUSE GAS PERMIT APPLICATION
PREVENTION OF SIGNIFICANT DETERIORATION:
2012 EXPANSION PROJECT
OLEFINS EXPANSION: OLEFINS 3 AND PROPANE DEHYDROGENATION PLANT
POINT COMFORT, TEXAS

SUBMITTED TO:
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:

FORMOSA PLASTICS CORPORATION, TEXAS
P.O. BOX 700
POINT COMFORT, TEXAS 77978

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2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

MAY 2013

zephyr

TABLE OF CONTENTS

APPENDICES

1.0 INTRODUCTION

Formosa Plastics Corporation, Texas (FPC TX) currently operates a number of chemical plants at its chemical complex in Point Comfort, Calhoun County, Texas. FPC TX proposes to expand the chemical complex within the existing FPC TX Point Comfort site footprint. The 2012 Expansion Project will consist of an Olefins Expansion (a new Olefins 3 plant and a Propane Dehydrogenation (PDH) unit), a new Low Density Polyethylene (LDPE) Plant and two new Combined Cycle Turbines (Gas Turbines).

On June 3, 2010, the EPA published final rules for permitting sources of Greenhouse Gases (GHGs) under the prevention of significant deterioration (PSD) and Title V air permitting programs, known as the GHG Tailoring Rule.[1] After July 1, 2011, modified sources with GHG emission increases of more than 75,000 tons/yr on a carbon dioxide equivalent (CO_2e) basis at existing major sources are subject to GHG PSD review. On December 23, 2010, EPA issued a Federal Implementation Plan (FIP) authorizing EPA to issue PSD permits in Texas for GHG sources until Texas submits the required SIP revision for GHG permitting and it is approved by EPA.[2]

The FPC TX Point Comfort 2012 Expansion Project (which includes the Olefins 3 Plant and PDH Unit, LDPE plant, and two combined cycle combustion turbines) triggers PSD review for GHG pollutants because the GHG emissions from the expansion project will be more than 75,000 tons/yr and the site is an existing major source. Therefore, the entire 2012 Expansion Project is subject to PSD review for GHG pollutants. The applications for GHG PSD air permits for this expansion are being submitted to the EPA. The applications for criteria pollutant PSD permits are being submitted to the Texas Commission on Environmental Quality (TCEQ) with copies for the EPA.

As described in the July 13, 2012 Kelly Hart & Hallman memo to Mr. Brian Tomasovic of EPA (found in Appendix D of this application), the 2012 Expansion Project consists of the three new related plants (identified above) which comprise a single GHG PSD project. In order to align

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

[2] 75 FR 81874 (Dec. 29, 2010).

FPC TX organizational responsibility and accountability for compliance with future permit requirements related to these plants, FPC TX is requesting a separate permit for each proposed new plant. Therefore, three separate permit applications are being submitted. Even though three separate applications are being submitted, FPC TX will perform and satisfy PSD permitting requirements, including ambient air quality impacts analysis, in aggregate for all the expansion project plants.

FPC TX is hereby submitting this application for a GHG prevention of significant deterioration (PSD) air permit for the construction of an Olefins 3 Plant and PDH unit at FPC TX's Point Comfort, Texas complex. The GHG emission unit descriptions, GHG emissions calculations and a GHG Best Available Control Technology (BACT) analysis are provided for those Olefins Expansion GHG emission sources.

2.0 GENERAL APPLICATION INFORMATION

A completed TCEQ Form PI-1 is included in this application to provide all the general administrative and Olefins Expansion project information for this GHG application. In addition, an overall expansion plot plan, plot plans for the Olefins 3 plant and the PDH unit, and an area map are included in this section.

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

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

I. Applicant Information		
A. Company or Other Legal Name: Formosa Plastics Corporation, Texas		
Texas Secretary of State Charter/Registration Number (*if applicable*): 5107506		
B. Company Official Contact Name: Randy Smith, Vice President		
Title: General Manager		
Mailing Address: P.O. Box 700		
City: Point Comfort	State: Texas	ZIP Code: 77978
Telephone No.: 361-987-7000	Fax No.: 361-987-2363	E-mail Address:
C. Technical Contact Name: Tammy G. Lasater		
Title: EHS Department Staff		
Company Name: Formosa Plastics Corporation, Texas		
Mailing Address: P.O. Box 320		
City: Delaware City	State: Delaware	ZIP Code: 19706
Telephone No.: 302-836-2241	Fax No.: 302-836-2239	E-mail Address: TammyL@fdde.fpcusa.com
D. Site Name: Formosa Plastics Corporation, Texas		
E. Area Name/Type of Facility: 2012 Expansion Project: Olefins Expansion	☒ Permanent ☐ Portable	
F. Principal Company Product or Business: Petrochemical Manufacturing Facility		
Principal Standard Industrial Classification Code (SIC): 2821		
Principal North American Industry Classification System (NAICS): 325211		
G. Projected Start of Construction Date: 2013		
Projected Start of Operation Date: 2016		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address: 201 Formosa Drive		
City/Town: Point Comfort	County: Calhoun	ZIP Code: 77978
Latitude (nearest second): 28° 41′ 20″	Longitude (nearest second): 096° 32′ 50″	

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

I. Applicant Information (continued)	
I. Account Identification Number (leave blank if new site or facility): CB0038Q	
J. Core Data Form.	
Is the Core Data Form (Form 10400) attached? If *No*, provide customer reference number and regulated entity number (complete K and L).	☐ YES ☒ NO
K. Customer Reference Number (CN): CN600130017	
L. Regulated Entity Number (RN): RN100218973	
II. General Information	
A. Is confidential information submitted with this application? If *Yes*, mark each **confidential** page **confidential** in large red letters at the bottom of each page.	☐ YES ☒ NO
B. Is this application in response to an investigation or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 225	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Glenn Hegar	District No.: 18
Representative: Todd Hunter	District No.: 32
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:____________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III. Type of Permit Action Requested (continued)

E. Is this application for a change of location of previously permitted facilities? If Yes, complete III.E.1 - III.E.4.		☐ YES ☒ NO
1. Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
2. Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
City:	County:	ZIP Code:
3. Will the proposed facility, site, and plot plan meet all current technical requirements of the permit special conditions? If *No*, attach detailed information.		☐ YES ☐ NO
4. Is the site where the facility is moving considered a major source of criteria pollutants or HAPs?		☐ YES ☐ NO
F. Consolidation into this Permit: List any standard permits, exemptions or permits by rule to be consolidated into this permit including those for planned maintenance, startup, and shutdown.		
List: None		
G. Are you permitting planned maintenance, startup, and shutdown emissions? If *Yes*, attach information on any changes to emissions under this application as specified in VII and VIII.		☒ YES ☐ NO
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit? If *Yes*, list all associated permit number(s), attach pages as needed).		☒ YES ☐ NO ☐ To be determined
Associated Permit No (s.):		
1. Identify the requirements of 30 TAC Chapter 122 that will be triggered if this application is approved. FOP Significant Revision ☐ FOP Minor ☐ Application for an FOP Revision ☐ To Be Determined ☐ Operational Flexibility/Off-Permit Notification ☐ Streamlined Revision for GOP ☐ None ☐		

III. Type of Permit Action Requested (continued)	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2. Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐

IV. Public Notice Applicability	
A. Is this a new permit application or a change of location application?	☒ YES ☐ NO
B. Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C. Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D. Is this application for a PSD or major modification of a PSD located within 100 kilometers or less of an affected state or Class I Area?	☐ YES ☒ NO
If *Yes*, list the affected state(s) and/or Class I Area(s).	
E. Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	☐ YES ☒ NO
1. Is there any change in character of emissions in this application?	☐ YES ☐ NO
2. Is there a new air contaminant in this application?	☐ YES ☐ NO
3. Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F. List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*): for 2012 Expansion Project – Greenhouse Gas Application	
Greenhouse Gases – see permit application emission summary	

Texas Commission on Environmental Quality
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V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Tammy G Lasater			
Title: Corporate Air Permitting Manager			
Mailing Address: P.O. Box 320			
City: Delaware City	State: DE	ZIP Code: 19706	
Telephone No.: (302) 836-2241			
B. Name of the Public Place: Calhoun County Branch Library & Point Comfort City Hall			
Physical Address (No P.O. Boxes): 1 Lamar Street and 102 Jones Street			
City: Point Comfort	County: Calhoun	ZIP Code: 77978	
The public place has granted authorization to place the application for public viewing and copying.			☒ YES ☐ NO
The public place has internet access available for the public. Yes, Library No, City Hall			☒ YES ☒ NO
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executive of the city for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	

V. Public Notice Information (complete if applicable) (continued)		
3. Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located. *(continued)*		
Name of the Indian Governing Body: N/A		
Title:		
Mailing Address:		
City:	State:	ZIP Code:
D. Bilingual Notice		
Is a bilingual program **required** by the Texas Education Code in the School District?		☒ YES ☐ NO
Are the children who attend either the elementary school or the middle school closest to your facility eligible to be enrolled in a bilingual program provided by the district?		☒ YES ☐ NO
If *Yes*, list which languages are required by the bilingual program? Spanish		
VI. Small Business Classification (Required)		
A. Does this company (including parent companies and subsidiary companies) have fewer than 100 employees or less than $6 million in annual gross receipts?		☐ YES ☒ NO
B. Is the site a major stationary source for federal air quality permitting?		☒ YES ☐ NO
C. Are the site emissions of any regulated air pollutant greater than or equal to 50 tpy?		☒ YES ☐ NO
D. Are the site emissions of all regulated air pollutants combined less than 75 tpy?		☒ YES ☐ NO
VII. Technical Information		
A. The following information must be submitted with your Form PI-1 (this is just a checklist to make sure you have included everything)		
1. Current Area Map ☒		
2. Plot Plan ☒		
3. Existing Authorizations ☐		
4. Process Flow Diagram ☒		
5. Process Description ☒		
6. Maximum Emissions Data and Calculations ☒		
7. Air Permit Application Tables ☐		
a. Table 1(a) (Form 10153) entitled, Emission Point Summary ☐		
b. Table 2 (Form 10155) entitled, Material Balance ☐		
c. Other equipment, process or control device tables ☐		

VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24	Day(s): 7	Week(s): 52	Year(s):
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
Not for the 2012 Expansion Project since the sources are not yet constructed			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☒ YES ☐ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?			☒ YES ☐ NO

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IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?	☒ YES ☐ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number:	Fee Amount: N/A
Company name on check: Formosa Plastics Corporation	Paid online?: ☐ YES ☐ NO
Is a copy of the check or money order attached to the original submittal of this application?	☐ YES ☐ NO ☒ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☐ YES ☐ NO ☒ N/A

Texas Commission on Environmental Quality
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XII. Delinquent Fees and Penalties

This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.

XIII. Signature

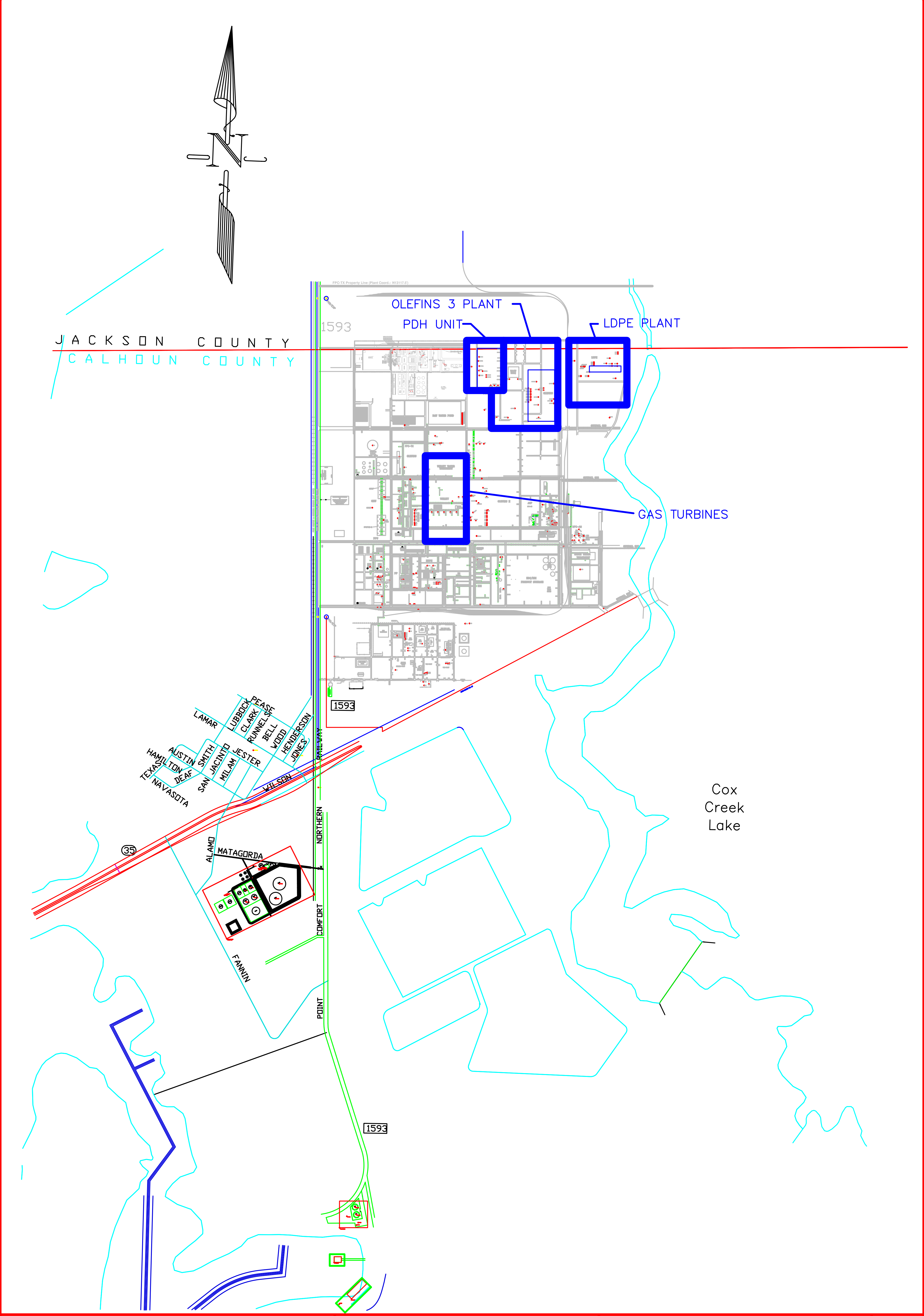
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.

Name: R. P. Smith, Vice President/General Manager

Signature: (See original PI-1 signed 12-5-12)

Original Signature Required

Date: ______________________________

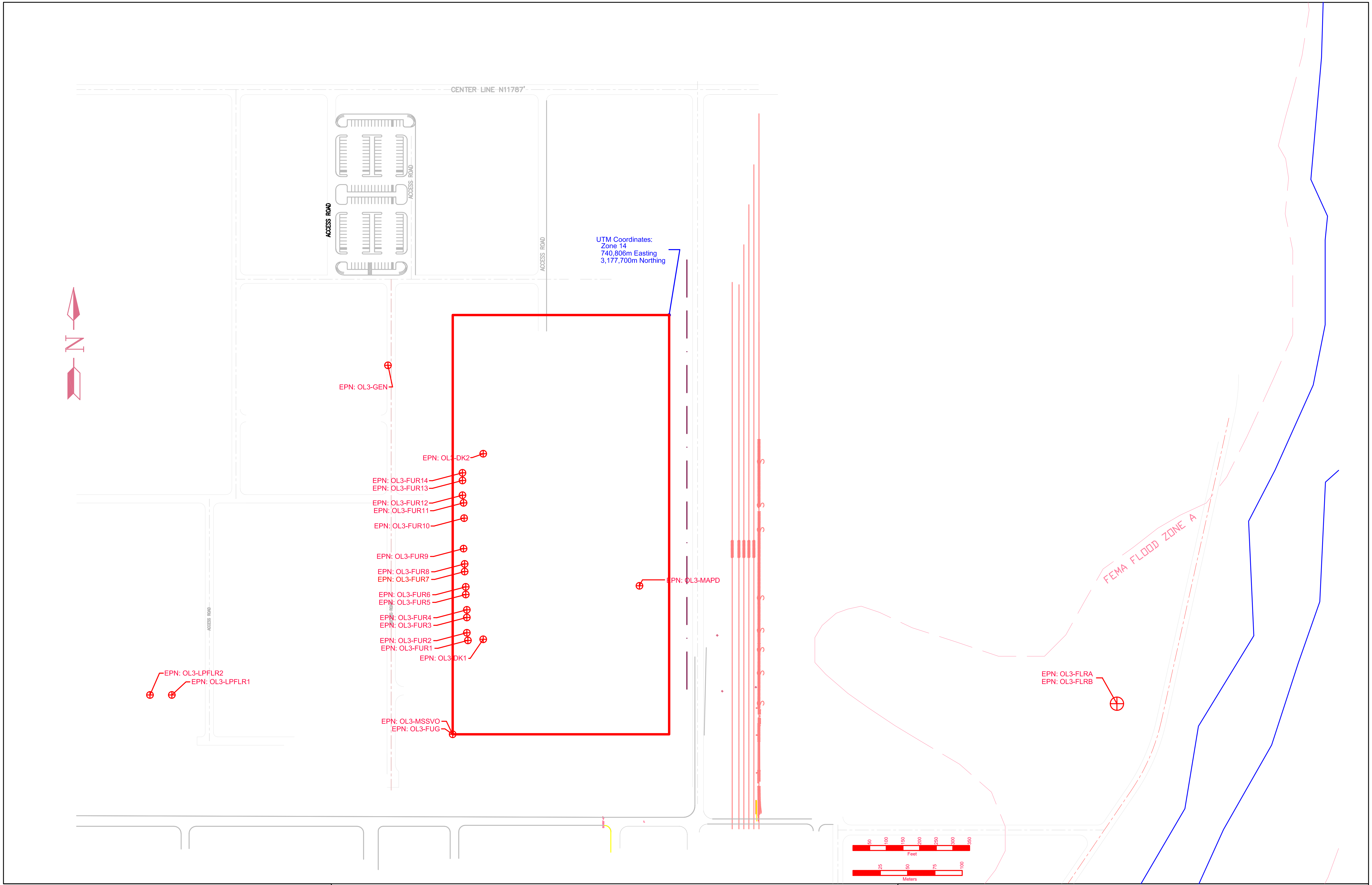


Formosa Plastics®

DESCRIPTION: OVERALL VIEW SHEET LAYOUT			PROJECT: Overall Plot Plan
DRAWN BY : DWD	SCALE: 1" = 1000'	REFERENCE FILES	CLIENT: FORMOSA PLASTICS CORP.
CHECKED BY: G.A.G.	DATE: 8/01/95		
APPROVED BY: G.A.G.	JOB NO. PC95-042		

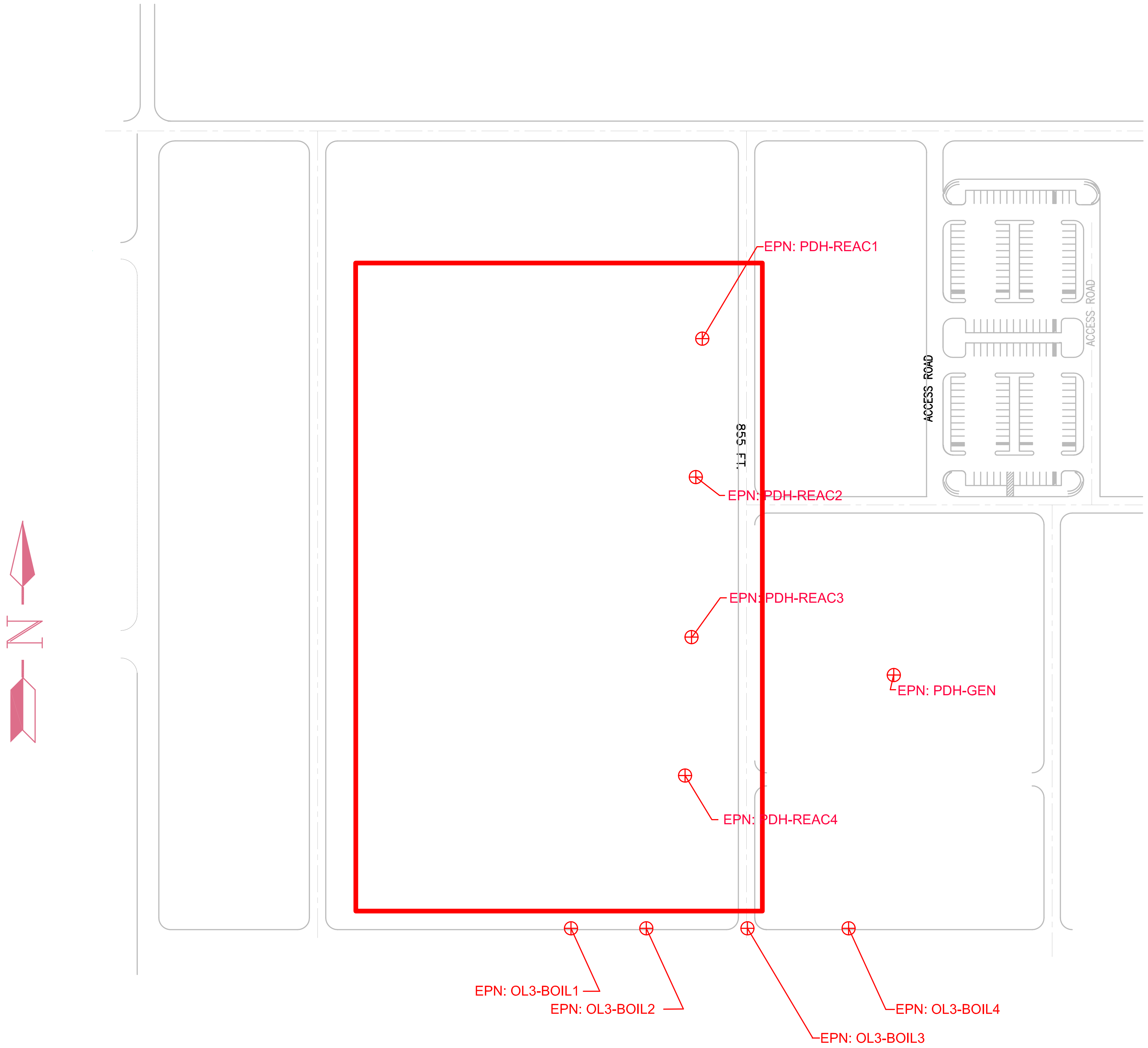
SHEET 1 OF 1

Permit\Plot Plans\FPC-TX Overall OL III_PDH_LDPE 10.10.12.dwg



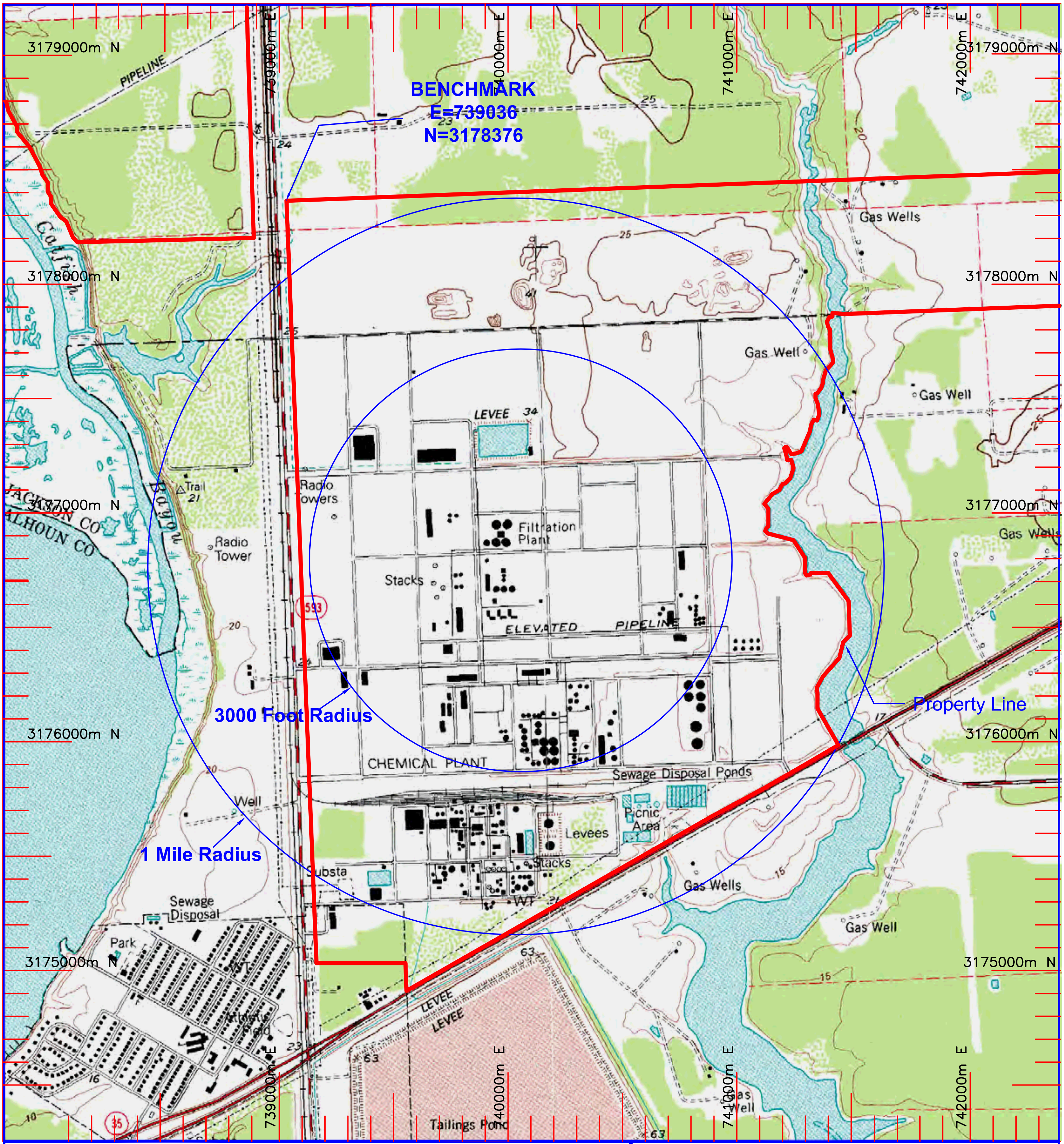
FORMOSA PLASTICS CORPORATION - TEXAS
Point Comfort, Texas

OLEFINS 3 PLANT



FORMOSA PLASTICS CORPORATION - TEXAS
Point Comfort, Texas

PDH UNIT



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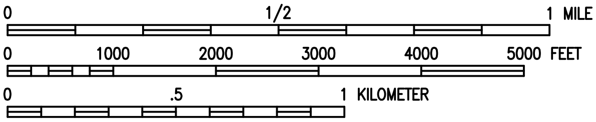
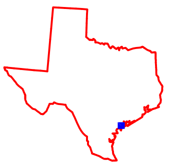


CONTOUR INTERVAL 5 FEET
COORDINATE DATUM: NAD83
U.S.G.S. 7.5 MINUTE SERIES (TOPOGRAPHIC)
POINT COMFORT, TEXAS QUADRANGLE 1995



QUADRANGLE
LOCATION

zephyr

AREA MAP

FORMOSA PLASTICS CORPORATION, TEXAS

2012 Expansion Project

Designed by: E. Quiat		Filename: areamap.dwg	Date: 10/24/12

3.0 PROCESS DESCRIPTION AND GHG EMISSION SOURCES

3.1 PROCESS DESCRIPTION

With this application, FPC TX is seeking authorization to construct a new Olefins Expansion, which consists of the Olefins 3 (thermal cracking) plant and a propane dehydrogenation (PDH) unit. The new plant will be located at the existing Point Comfort complex located in Calhoun County, Texas. The sources of GHG emissions associated with the Olefins Expansion are listed below:

- 14 cracking furnaces
- 2 furnace decoking vents
- MAPD regeneration vent
- 2 low pressure flares
- 4 steam boilers
- 4 PDH reactors
- Elevated flare
- 2 diesel-fired emergency generator engines
- Fuel gas and natural gas piping fugitives
- Planned maintenance, startup and shutdown (MSS) activities

The following process description discussion refers to stream numbers listed on the process flow diagram, which is included at the end of this section. A detailed discussion of the GHG sources is included in Section 3.2.

<u>Olefins 3 Plant Process Description</u>

The Olefins 3 plant will be designed with a production capacity of approximately 1,750,000 short tons per year of high purity ethylene product.

Fresh imported ethane feed (1) received from outside battery limits (OSBL) is combined with recycle ethane (1R) from the ethylene fractionator. The combined stream is superheated (with quench water) prior to entering the ethane feed saturator.

Saturator

In the saturator, the ethane feed is saturated with water by humidification. And the humidified ethane feed from the saturator is superheated in a low pressure (LP) steam heated exchanger. The heated ethane/steam mixture (2) is then fed to the fourteen pyrolysis furnaces (FIN/EPNs: OL3-FUR1 through OL3-FUR14).

Pyrolysis Furnaces

The feed stream is further preheated in the convection section of each furnace before entering the radiant coils where the thermal cracking of the feed occurs. The radiant heat in the furnace will be provided by fuel gas fired hearth (floor fired) and wall burners. The combustion product stream from the fuel gas firing is routed through the convection section in the upper part of the furnace where the feed is preheated. The combustion products will be routed through a selective catalytic reduction (SCR) unit located in the convection section of the furnace before being released to the atmosphere (EPNs: OL3-FUR1 through OL3-FUR14).

The product stream (cracked gas) from the furnace radiant coils (3) is routed through heat exchangers where heat is recovered by boiler feed water to produce superheated high pressure (SHP) steam. The product stream from the furnace is sent to the quench tower.

Decoking

The temperatures in the radiant coils of the furnaces, which are required to accomplish the thermal cracking of the feed, also result in coke accumulation in the tube side of the coils. As the coke accumulates, it decreases the heat transfer in the tube and interferes with the efficiency of the furnace operation. Then, the furnace is “decoked”, i.e., the coke is removed from the tubes to restore efficient furnace operation. Furnaces are decoked in a staggered cycle; so, while the decoking process is occurring in some furnaces, others may be concurrently operated in the thermal cracking mode of operation.

The decoking process involves the following steps:

- the furnace is taken out of normal operation by removing the hydrocarbon feed
- steam is added to the furnace tubes to purge hydrocarbon to the process equipment downstream

- after the hydrocarbons are removed, steam is rerouted to the decoke drum
- air is injected into the steam going through the tubes of the furnace to enhance the burning effect and loosening of coke inside of the tubes
- the steam / air decoking continues until all of the coke is removed and the tubes are clean again so they can be used efficiently to crack hydrocarbons when put back into service
- once the tubes are clean, the air is stopped and the steam continues to purge out the oxygen before the furnace is put back in normal operation
- the effluent from the decoking process, consisting of mainly steam and air, is directed to one of two solid separators called decoke drums (FIN/EPNs: OL3-DK1 & OL3-DK2)

Quench Tower

During the cracking process in the furnace ethylene is produced along with a number of other hydrocarbon products (cracked gas). The cracked gas from the furnaces is cooled and partially condensed by direct countercurrent contact with re-circulating water in the quench tower.

Process Water Stripper

The dilution steam condensed in the quench tower is sent through a filter system, which removes the suspended solids and dispersed oil from the process water, and then to the process water stripper where it is stripped with steam to remove acid gases (e.g., CO_2 and trace H_2S formed from side reactions in the pyrolysis furnaces) and light hydrocarbons. The overhead vapor leaving the process water stripper is sent back to the quench water tower where it is reprocessed. The acid gases continue to be carried through the process until they are removed in the caustic/water wash tower (described below).

Process Gas Compressor

The quench tower overhead vapors (5) are compressed in a steam turbine-driven centrifugal process gas compressor with inter-stage cooling provided by cooling water. Wash oil is injected at the inlet of each stage of the process gas compressor charge and on the casing to mitigate fouling.

Caustic/Water Wash Tower

After compression the process gas, called charge gas, (6) is sent to a three stage caustic/water wash tower for complete removal of acid gases (e.g., CO_2 and trace H_2S) from the process gas using a 20% caustic solution. The 20% caustic solution is supplied by pipeline from OSBL.

Spent Caustic Oxidation Unit

The spent caustic blowdown from the caustic/water wash tower is routed to a collection tank. Since it is possible for the blowdown to have hydrocarbons, this collection tank is vented to a set of carbon canisters.

Charge gas drying and cooling

Charge gas from the caustic/water wash tower overhead (7) is sent through a drier feed KO Drum for moisture removal and then to the charge gas driers where the process gas is dried in a molecular sieve drying system. The vapor (8) from the charge gas driers is cooled (by propylene refrigerant) before entering the deethanizer.

Deethanizer

The deethanizer column is heated with recovered energy from low pressure steam. The deethanizer tower produces a vapor overhead (9). This overhead, which is mostly C2 compounds and small amounts of C3 compounds, is sent to the acetylene converter (ACU). The bottoms stream from the deethanizer (10), comprised of C3 and heavier compounds, is sent to the depropanizer for additional processing.

Actetylene Converter (ACU)

The ACU employs a catalyst to convert acetylene to ethylene by selective hydrogenation. The outlet of the ACU (11), which is rich in hydrogen, methane, ethylene, and ethane, is further processed in the demethanizer tower.

Demethanizer

In the demethanizer, methane and hydrogen are separated as overheads which are routed to the (12) fuel gas system. This overhead stream is high in hydrogen content. Some amount of the hydrogen is recovered in a pressure swing absorption (PSA) system, while the remainder of the hydrogen and hydrocarbons are used as fuel gas for the pyrolysis furnaces. The demethanizer bottoms (13) proceeds to the ethylene fractionator for product recovery.

Ethylene Fractionator

The ethylene fractionator is designed to produce a high purity ethylene product (14) to be used as feed for other units at the Point Comfort complex (replacing purchased feed), stored or exported to pipeline. The ethylene fractionator bottoms stream (1R – composed primarily of ethane) is recycled and combined with the fresh ethane feed from OSBL before the feed saturator.

Depropanizer

The bottoms from the deethanizer (10) are routed to the depropanizer to separate the C3 components from the C4 heavier components. The overhead stream from the depropanizer (15) contains C3 compounds.

MAPD Converter

The methyl acetylene (MA) and propadiene (PD) contained in the depropanizer overhead (15) are removed by selective hydrogenation to propylene and propane in a single-bed reactor called the MAPD converter. The MAPD catalyst must be periodically regenerated as polymer accumulates on the catalyst surface during normal operation (FIN/EPN OL3-MAPD).

De-butanizer

The bottoms product from the depropanizer (18) flows to the debutanizer where the mixed C4s overhead product (19) is separated for export. The debutanizer bottoms/pygas product (20), is also exported after cooling with cooling water.

Refrigeration Systems

The Olefins 3 plant features two separate closed-loop refrigerant systems: a propylene system and a binary refrigerant system. Both systems utilize a steam turbine-driven centrifugal compressor. The binary refrigerant (BR) system combines methane and ethylene as a single stream of constant composition refrigerant.

Fuel Gas System

The fuel gas mixing drum combines the following streams: hydrogen-rich gas from the dryer regeneration system (deethanizer overhead), methane-rich off gas from the chilling train (demethanizer overhead), pressure swing adsorption (PSA) off-gas and natural gas from OSBL. This fuel gas mixture is filtered and supplied to combustion sources including the furnaces, and steam boilers.

Flare Systems

The elevated flare system (two stages, FIN/EPNs OL3-FLRA, OL3-FLRB) is designed to provide safe control for vent gas streams that cannot be recycled in the process or routed to the fuel gas system. Two low pressure/ground flares (FIN/EPNs: OL3-LPFLR1 & OL3-LPFLR2) will control breathing losses from existing API product tanks, spent caustic tanks, spent caustic oxidation unit and the wash oil chemical tank.

Emergency Engine

In the event of a power outage, an emergency generator (FIN/EPN: OL3-GEN) will supply power to operate valves and other critical equipment in the Olefins Expansion.

Propane Dehydrogenation (PDH) Unit Process Description

The PDH unit will be designed to produce 725,000 short tons per year of polymer-grade propylene product by the dehydrogenation of propane. A block flow diagram is provided at the end of this section.

Fresh propane feed (21) from OSBL is vaporized with recovered heat from reactor effluent stream (24) and routed to the depropanizer tower. Recycle propane (21R) from propylene fractionator is sent as reflux to the depropanizer tower. In the depropanizer tower, fresh propane feed from OSBL and recycled propane are purified before the propane feed enters the reactors (FIN/EPNs: PDH-REAC1 through PDH-REAC4). The reactors are fired using fuel gas from ISBL (discussed later in this section) and are equipped with SCR units for NOx emission control.

Depropanizer Tower

Fresh propane feed (21) and propane recycle (21R) are routed to the depropanizer column where C4s and heavier compounds (also referred to as naphtha) are separated from the C3 compounds and are drawn off as naphtha product (22).

The overheads from the depropanizer tower (23), C3 compounds, is diluted with saturated medium pressure (MP) steam before being routed to the reactor to minimize fouling of the reactor catalyst. The dilution steam is supplied by the steam boilers (FIN/EPNs: OL3-BOIL1 through OL3-BOIL4). Each steam boiler is equipped with an SCR unit for NO_X emission control.

Reactors

In the reactor reaction section the dehydrogenation of propane to propylene takes place. This is performed through four reaction trains. Dehydrogenation is a strongly endothermic reaction, in which propane is converted to propylene.

Lower hydrocarbons like ethane, ethylene and methane are also formed in parallel side reactions. Dehydration of propane also promotes hydrolysis and thus the formation of minor amounts of carbon dioxide.

Other minor reactions that occur as a result of thermal cracking also promote the formation of small amounts of coke. This requires regular regeneration of the catalyst to burn off the coke deposits. The catalyst regeneration is accomplished using a mixture of steam and air and the resulting regeneration off-gas is routed to the combustion section of the PDH reactor to destroy any residual hydrocarbons.

Heat Recovery

The hot reactor effluent process gas (24) contains the desired propylene product, steam, hydrogen and unconverted propane with a small amount of other products of side reactions. The effluent stream from the reaction trains is cooled by routing it through a series of heat exchangers (for heat recovery) throughout the PDH unit.

Condensate Knockout Drums

Through this heat recovery process, steam and traces of heavier hydrocarbon by-products are condensed from the reactor effluent gas. The cooled process gas stream (25) is routed through a series of condensate knockout drums to remove the condensed steam before being routed to the inlet of the process gas compressor (26).

Process Gas Compressor

After the reactors, the remainder of the PDH process is the propylene purification process. These steps require higher operating pressure; therefore, the process gas (26) is compressed (27) before entering the CO_2 removal system.

CO_2 Removal

In the PDH process, CO_2 is formed due to the hydrolysis reaction and reconversion of coke laydown on the catalyst (caused by thermal cracking). Therefore, CO_2 is present in the process gas and must be removed from the propylene product.

For this purpose, an absorption process for sour gas removal is used, which selectively absorbs CO_2 contained in the product gas. The majority of the CO_2 and small of amounts of hydrocarbon (28) resulting from the regeneration of the absorbent are mixed with the plant fuel gas and used as fuel for the reactors. The rich solvent from the bottom of the absorber column is sent to the solvent flash drum. Flash gas from this drum, containing any remaining CO_2 and light hydrocarbons, is routed back to the cooled process gas stream (25) for recycle. Solvent flash drum bottoms are routed to the solvent system stripper for processing and reuse.

Hydrogen and Methane removal

The process gas from the CO_2 removal system (29) flows through a flash drum which allows the hydrogen and methane to be separated from the heavier components. The overhead stream (30), consisting mainly of hydrogen, methane, and small amounts of C2+ hydrocarbons, flows through process gas driers employing molecular sieves to remove traces of water which could result in freezing and plugging of the cold box. The bottom of the flash drum (35) (mostly C3+ compounds) is routed to the dethanizer tower.

From the driers, the process gas (31) will flow after additional chilling to the cold box. The cold boxes separate non-condensable process gas components, such as hydrogen and methane, from a propane and propylene-containing liquid phase. The heavier hydrocarbon phase (C2 and C3+ compounds) (34) will be condensed while the hydrogen and methane (32) remain in the gas phase. The gas phase, which is extremely cold, serves as refrigerant media in cold boxes. By heat exchange with the cold box, feed gas is warmed and sent on to the Expander. Mechanical energy recovery is available at the coupling of the expander and is used for generation of electric power which is charged into the electrical power grid. Due to the polytropic expansion, the expanded gas cools down and supplies the main portion of the cryogenic energy required in the cold boxes. From the expander, the gas phase is sent to the fuel gas header (33).

Deethanizer

The heavier hydrocarbons such as ethane, ethylene, unconverted propane, and propylene (34) from the cold box section will combine with the bottoms of the flash drum (35) and continue on to the deethanizer for distillation. The lighter overheads of the deethanizer will be routed to the fuel gas system via the cold box expander, while the heavier bottoms components (36), including propane and propylene, will continue on to the propylene fractionator.

Propylene Fractionator

In the propylene fractionator, propylene is obtained as overhead product (37). The bottoms stream (21R) which consists mainly of unconverted propane and traces of heavier boiling components is recycled and sent to the front end of the plant (depropanizer tower).

Refrigerant Systems

Two closed-loop refrigerant systems are used in the PDH unit: a propylene refrigerant and a liquid ammonia refrigerant. The propylene refrigerant system serves the PDH unit with coolant, while the liquid ammonia is utilized as refrigerant at low process side temperature levels to reduce the requirement for propylene refrigerant.

Process Condensate Stripper

In the dehydrogenation process traces of organics, such as acetic acid, aromatics, and acetone are formed due to side reactions and end up as contaminants in the aqueous process condensate which is collected in various process gas KO drums. In the condensate stripper, organic compounds are removed from the aqueous process condensate. The vent gases leaving the stripper are routed to the fuel gas header. The stripper bottoms are reused as boiler feed water to produce dilution steam within the PDH unit. The blowdown from the steam generators is routed to the complex wastewater treatment plant.

PDH Fuel Gas System

Fuel gas in the PDH unit serves as:

- fuel for combustion in the reactors
- pressure control for pressurized vessels
- regeneration gas for drying beds

Steam Boilers

Four steam boilers (FIN/EPNs: OL3-BOIL1 through OL3-BOIL4) will generate steam for use throughout the Olefins Expansion. The combustion products will be routed through a selective catalytic reduction (SCR) system before being released to the atmosphere.

Flare System

The Olefins 3 plant elevated flare system (FIN/EPNs OL3-FLRA, OL3-FLRB) is designed to provide safe control for PDH unit vent gas streams that cannot be recycled in the process or routed to the fuel gas system.

Emergency Engine

In the event of a power outage, an emergency generator (FIN/EPN: PDH-GEN) will supply power to operate valves and other critical equipment in the PDH unit.

3.2 GHG EMISSION SOURCES

3.2.1 Overall Energy-Efficient Design Philosophy

In the interest of minimizing the production of GHG emissions, FPC TX is incorporating available design and equipment selection approaches in the Olefins Expansion design that contribute to reduced energy use and conservation of materials. This design strategy provides operating cost savings and has the benefit of minimizing emissions of GHGs throughout the plant and at upstream electric generation sources. Since the proposed energy efficiency design features represent an integrated energy efficiency strategy, it is difficult to identify and quantify the affect of each individual efficiency feature. However, some examples of the type of energy efficiency design features that are included in the Olefins Expansion design are described in this section below. Although not possible to individually quantify, the overall effect of the associated energy savings and GHG emissions are reflected in the emission calculations included later in this application.

<u>Equipment Selection</u>

The Olefins Expansion design specifies that all new, high-efficiency electrical equipment be installed for the efficient conversion of electrical energy into mechanical energy, thus minimizing the amount of electrical energy needed and associated emissions of GHGs at upstream generation sources (e.g., combined cycle gas turbines in the utilities plant).

Energy-saving motors will be implemented on all applicable compressors. Capacity control will be installed to reduce electric energy consumption while running the compressor at various loads. Variable speed controllers are selected where applicable as the design specification for blowers, compressors and pumps to optimize electricity consumption.

The dominant type of heat exchanger in petrochemical plants today is the shell and tube. The selected process designs incorporate a portion of heat exchange in the cold box. The cold box is a compact heat exchanger which minimizes heat leakage as compared to conventional shell and tube exchanger because it acts as an insulated box. Cold box/brazed aluminum plate-fin heat exchangers offer two main advantages over shell-and-tube heat exchangers.

- Surface Area Density - Cold box/brazed aluminum plate-fin heat exchangers have several times the surface area of conventional shell-and-tube heat exchangers for increased efficiency and reduced energy consumption.

- Combining Process Streams – Brazed aluminum plate-fin exchangers can also accommodate heat exchange for various process streams in a single compact exchanger thus providing optimum efficiency with minimal material consumption.

Conventional olefins unit designs employ kettle-type exchangers to vaporize ethylene product, recycle ethane and a portion of charge gas chilling. FPC TX's selected design uses cold box design (insulated box) to recover heat from various process and refrigerant streams to maximize energy efficiency.

The PDH unit will utilize electrically-powered equipment to convert electrical energy into mechanical energy (shaft work). The electrical-powered equipment will have a design specification requiring high-efficiency equipment. New, energy-efficient electrical equipment will maximize the conversion of electrical energy into mechanical energy thus minimizing the amount of electrical energy needed to meet output specifications.

Expansion duty in the coldbox of the gas separation unit will be utilized for electrical power generation. This design option recovers energy during the expansion of gas by connecting the expander shaft to an electrical turbine, thereby reducing overall electrical power consumption. Reduced electrical consumption throughout the PDH unit will result in decreased GHG emissions at the upstream utility sources (i.e., the combined cycle gas turbines at the utility plant).

Energy-Efficient Process Design

Cooling equipment will also be specified with minimum temperature approaches to maximize process heat integration and minimize refrigerant usage, thereby, minimizing energy consumption. For example, the Olefins 3 plant is designed to maximize cooling from process off-gas streams (e.g., streams like the demethanizer bottoms) to minimize refrigerant requirements.

The Olefins 3 plant separations section is being designed to operate at minimum required pressure. For example, the demethanizer tower in the Olefins 3 plant will operate at a pressure approximately five times less than existing olefins unit towers. The selected low pressure tower design is unique and is not available from any other technology vendor. The lower pressure allows for easier separation of the methane from the heavier components and requires less refrigeration. The low pressure tower operation is estimated to reduce up to 10% of the required power for the binary refrigeration compressor (approximately 5.5 mmbtu/hr energy savings).

Tower performance, especially for ethylene fractionator, is optimized to minimize refrigerant usage. The ethylene fractionator is being specifically designed to minimize reflux in order to save energy. This reduction in operating reflux rate increases the number of trays required and increases the tower tangent to tangent length. Even though the capital investment is higher for more trays and a longer/taller tower, FPC TX is selecting the lower-reflux design for energy savings.

Cooling water system design is based on achieving maximum use of the available process stream temperature drops in order to minimize cooling water requirements. By minimizing the amount of cooling water needed, FPC TX's selected design reduces cooling water circulation electrical power requirements.

The PDH unit will feature a fuel gas system to recover byproduct hydrocarbon streams for chemical energy (i.e., heating value) that would otherwise be managed as a waste gas. In fact, the PDH unit fuel gas system will be used as the primary fuel in all of the unit's large fired sources (reactors), totaling approximately 764 MMBtu/hr of combustion equipment. The PDH fuel gas system collects all byproduct streams of the process and uses it as fuel gas for all furnaces Inside Battery Limits (ISBL). Depending on the propane feed composition even an export of fuel gas for use as fuel in other plants is possible.

The propane feed is a mixture of different hydrocarbons, mainly C2- and C4+ components. Part of the propane is converted to byproducts in the reactor, mainly C2- , CO_2 and H_2. After recovery of propane and propylene from the process gas in the gas separation downstream of the reactor these byproducts are collected and sent to the PDH internal fuel gas header. The hydrogen generated by the dehydrogenation process of propane to propylene reduces the GHG emission due to the emission free combustion of hydrogen. The following streams are routed to the fuel gas header to increase energy recovery: hydrogen rich gas containing also C2- hydrocarbons and CO_2, and acetone rich offgas

3.2.2 Cracking Furnaces

The reactors are fired with natural gas as a startup fuel and PDH unit fuel gas as the primary fuel. Combustion of these fuels results in emissions of GHGs.

3.2.3 Furnace Decoking

The side reactions that occur are mainly thermal cracking, which results in the formation of small amounts of coke. This requires routine decoking of the furnace tubes to burn off the coke deposits. As a result, the decoking cycle produces CO_2 which is vented to atmosphere via the decoking drums (FIN/EPNs: OL3-DK1, OL3-DK2).

3.2.4 MAPD Regeneration Vent

Periodic regeneration of the MAPD converter catalyst results in emissions of CO_2 via the regeneration vent (FIN/EPN: OL3-MAPD).

3.2.5 PDH Reactors

The reactors are fired with natural gas as a startup fuel and PDH unit fuel gas as the primary fuel. Combustion of these fuels results in emissions of GHGs from each reactor exhaust stack (FIN/EPNs: PDH-REAC1 through 4). In addition, the reactors will emit GHGs from the combustion of PDH regeneration gas in each reactor.

3.2.6 Steam Boilers

The steam boilers combust fuel gas generated from the Olefins 3 and PDH units combined with natural gas import. Natural gas will be used as start-up fuel. The boilers generate steam to be used in the PDH unit reactors during the steam-activated reformation of propane (to propylene) and throughout the rest of the plant. Fuel gas combustion in the steam boilers results in emissions of GHGs via each unit's exhaust stack (FIN/EPNs: OL3-BOIL1 through 4).

3.2.7 Elevated and Low Pressure Flares

The elevated flare (two stages) and low pressure/ground flares combust natural gas and hydrocarbon-containing waste gas which results in the formation of CO_2, methane and N_2O at the flare tips. The flare pilots are fueled by natural gas.

3.2.8 Natural Gas/Fuel Gas Piping

Natural gas is delivered to the site via pipeline and is fired as a start-up fuel in Olefins 3 and PDH plant combustion sources. Natural gas is also used as a start-up fuel in the steam boilers. Once the units are in normal operation as lesser amount of natural gas is imported and mixed with hydrogen-rich process gas to create a fuel gas mixture which is used as the primary combustion fuel in Olefins 3 plant combustion units and the steam boilers. During normal operation, the PDH plant is nearly self-sufficient in regards to fuel, as it generates enough fuel gas to fire the reactors. Gas will be metered and piped to the cracking furnaces, steam boilers and PDH reactors. Fugitive emissions from the gas piping components associated with the combustion units will include emissions of methane and carbon dioxide.

3.2.9 Emergency Engines

The emergency generator engines combust diesel fuel and are sources of GHG emissions. The emergency generators will be limited during non-emergency operating hours to testing and readiness checks as they are subject to NSPS Subpart IIII[3].

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[3] 40 CFR 60, Subpart IIII

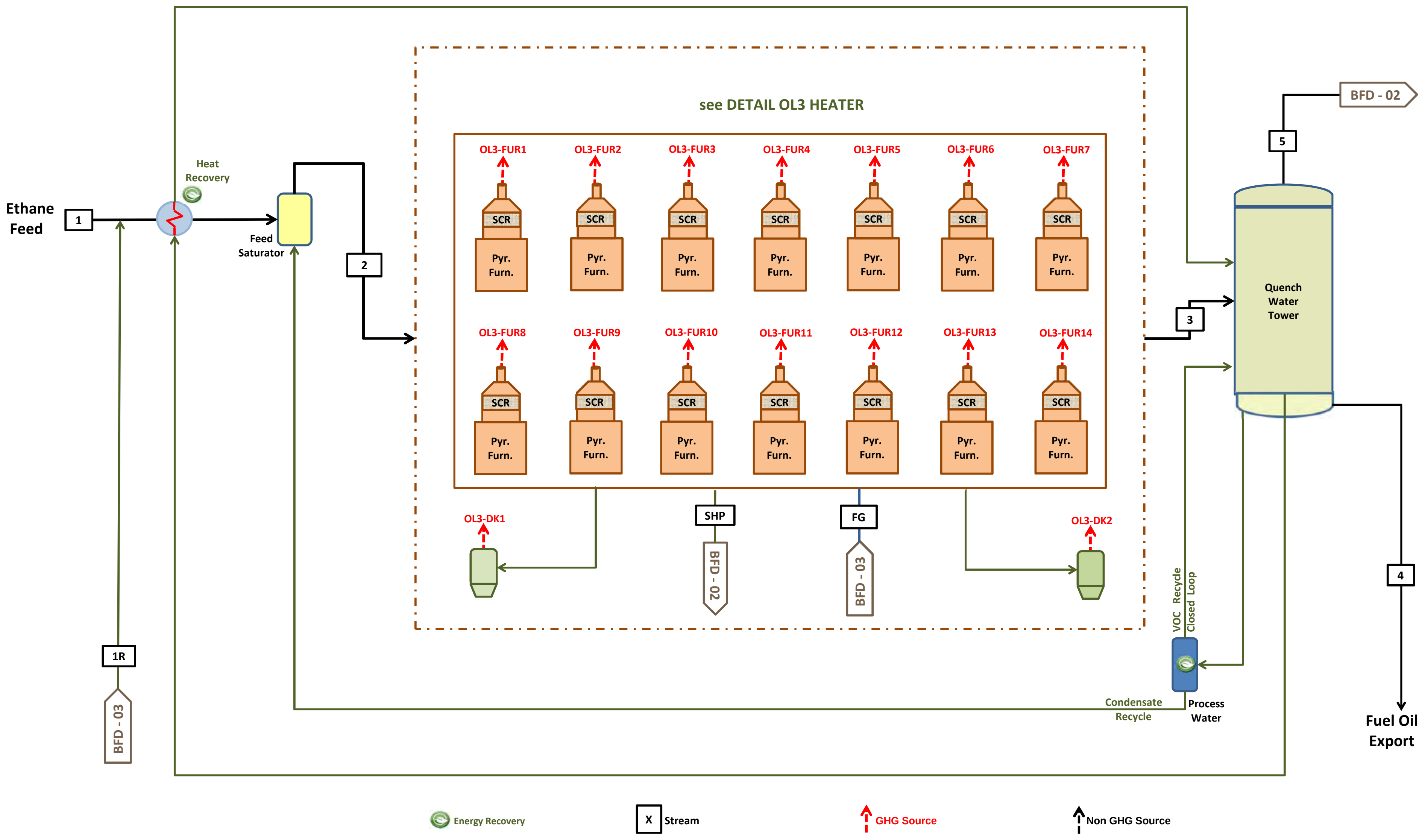
3.2.10 Planned MSS Activities

The Olefins 3 plant will emit GHGs as a result of periodic and routine planned MSS activities. These activities will result in the following types of GHG emissions:

- products of combustion from the elevated flare from degassing of hydrocarbon-containing process equipment to the flare header,
- fraction of uncombusted methane and CO_2 from degassing of process vessels with methane-containing process streams to the elevated flare header,
- fugitive emissions of GHG from opening of process equipment to atmosphere (after degassing) for process streams containing GHGs (methane, CO_2), and
- fugitive emissions from opening of fuel gas lines.

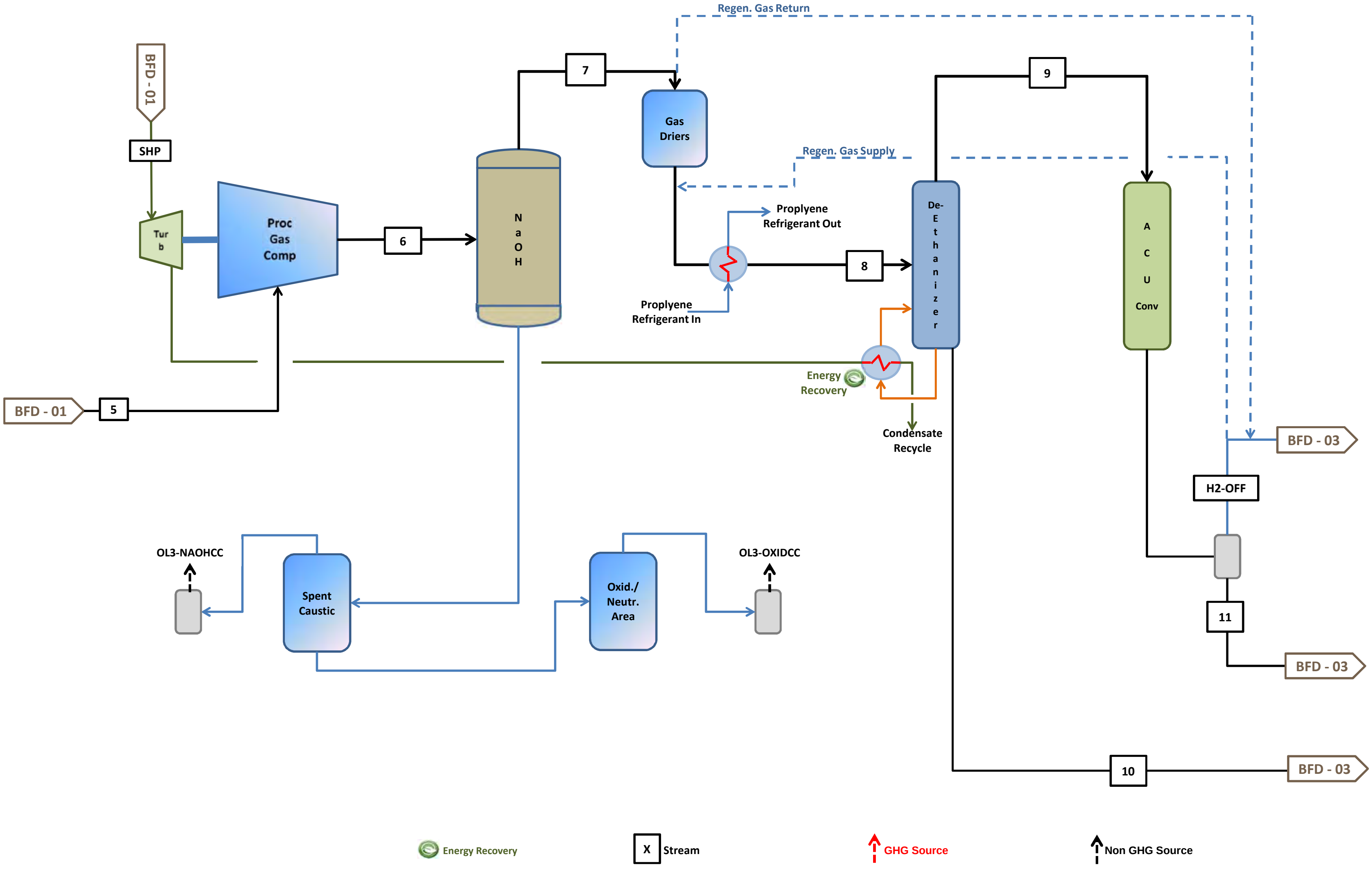
Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

Olefins 3 Plant BFD - 01



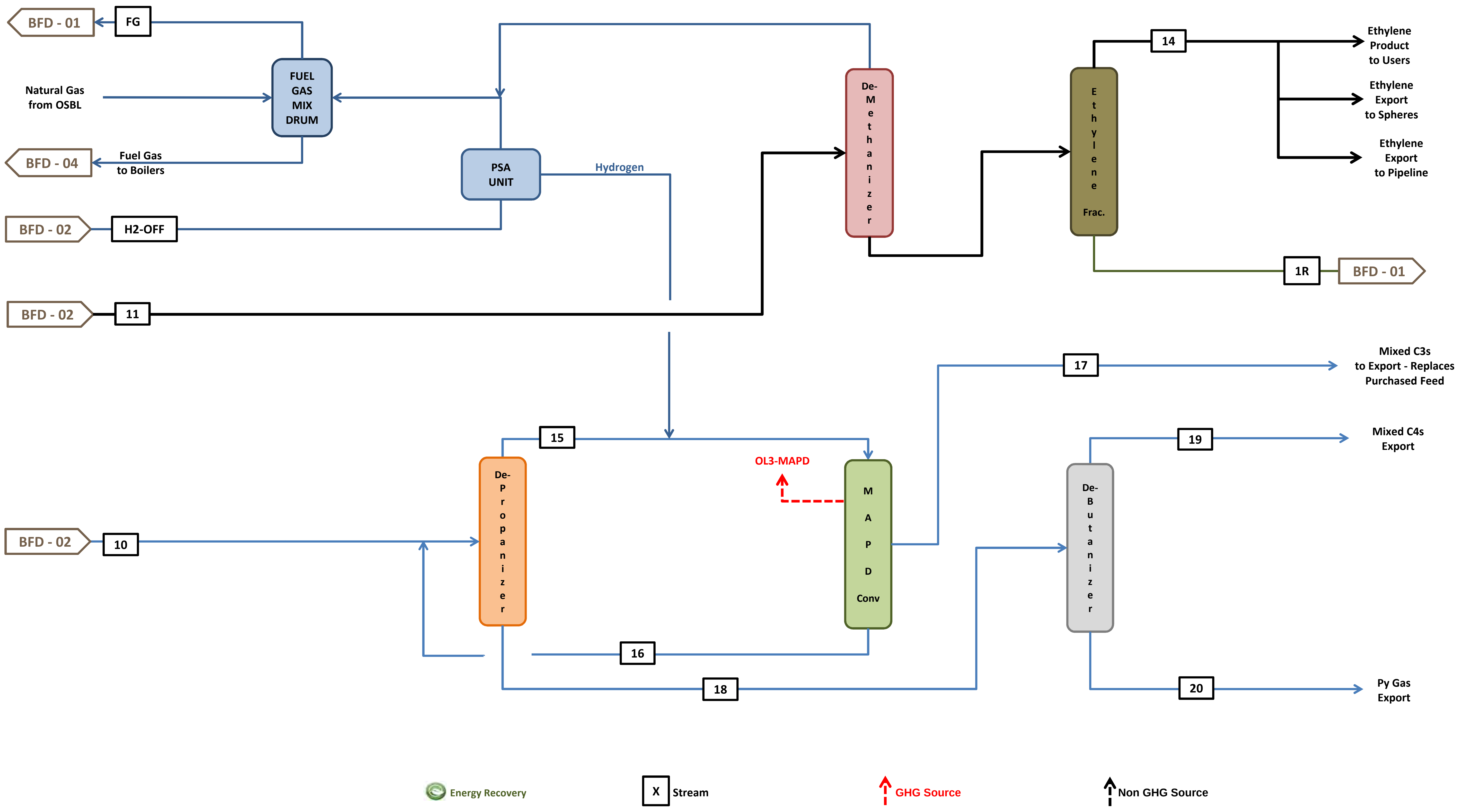
Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

Olefins 3 Plant BFD - 02



Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

Olefins 3 Plant BFD - 03



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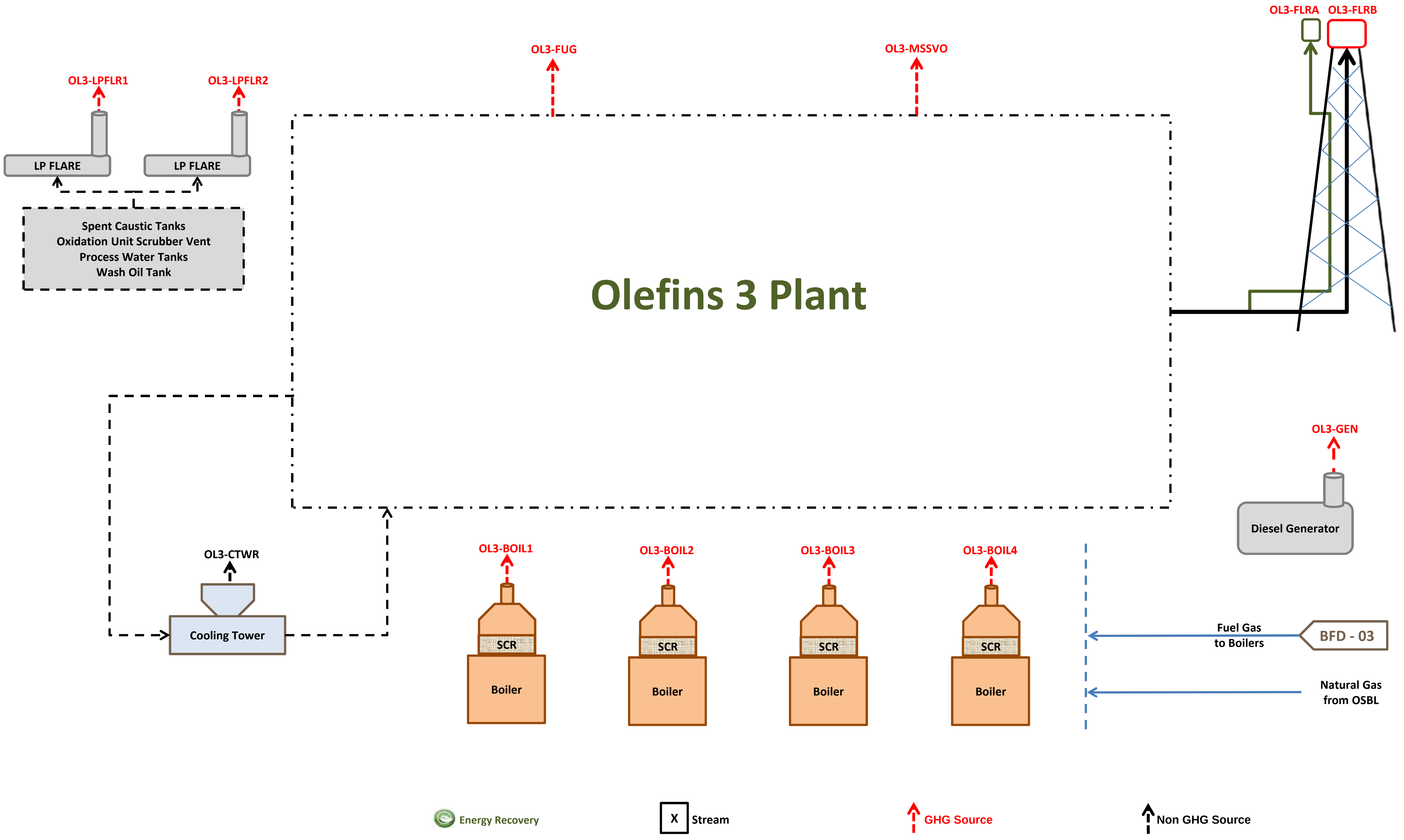
Olefins Expansion

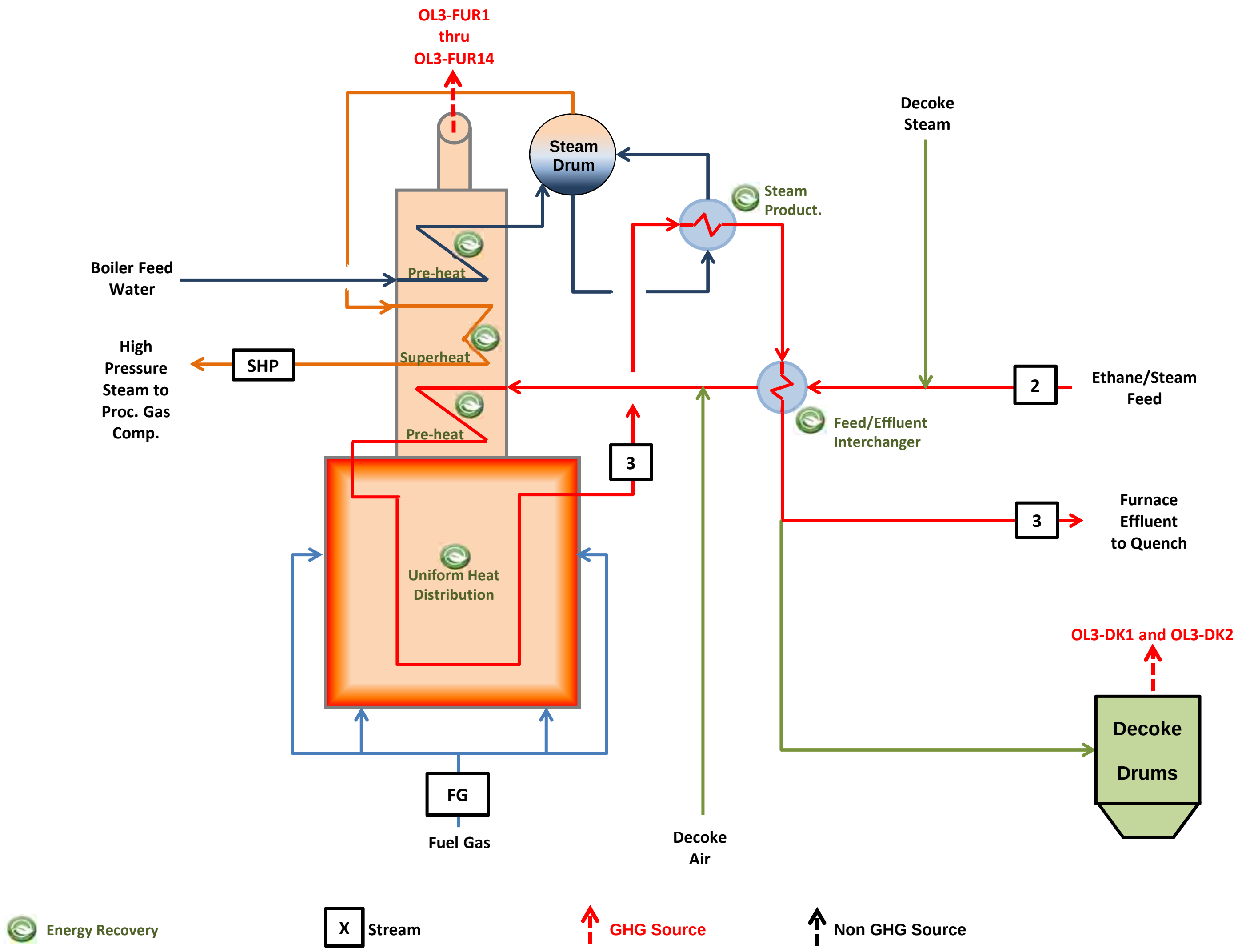
Olefins 3 Plant BFD - 04 (supporting systems)



Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

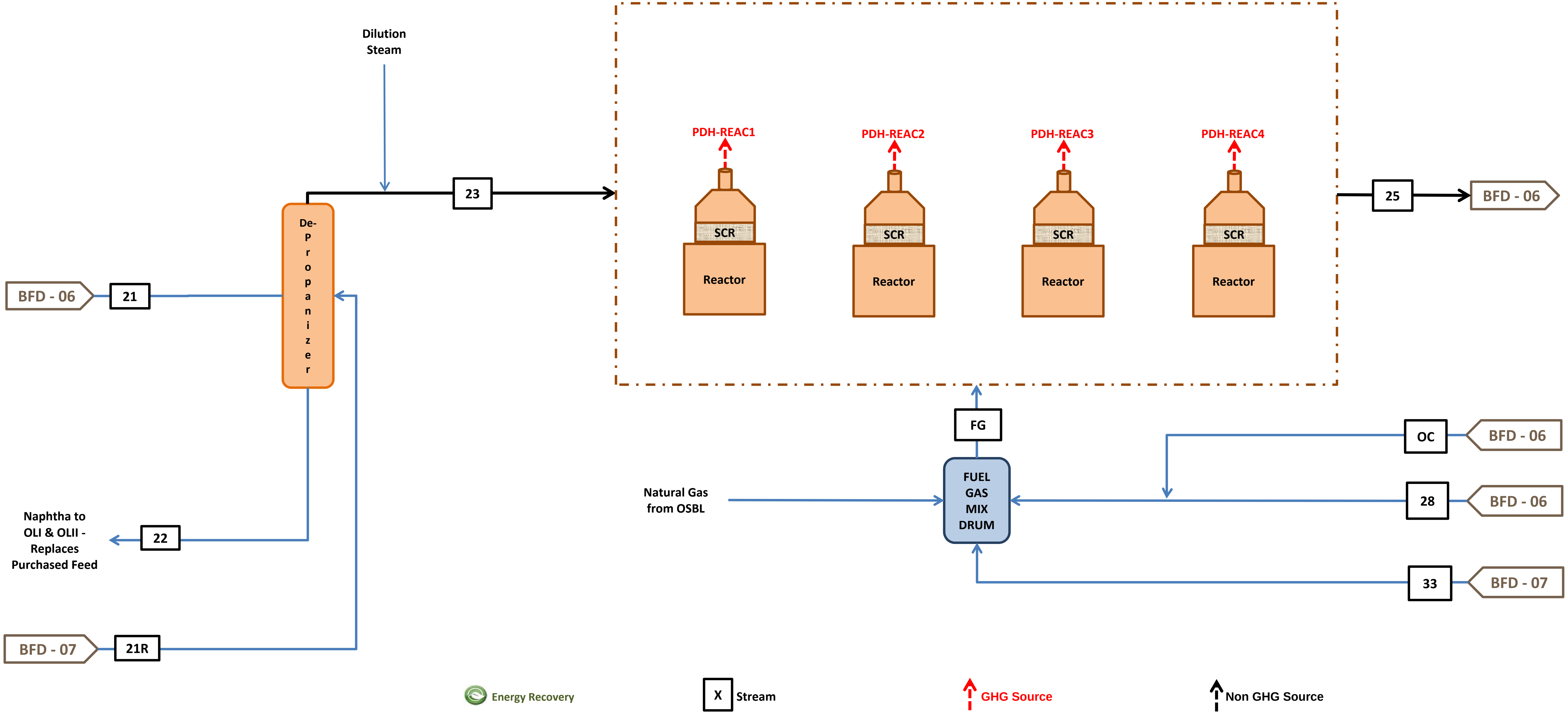
DETAIL OL3 HEATER

(Flow and Energy Recovery)



Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

Propane Dehydrogenation (PDH) Plant BFD - 05



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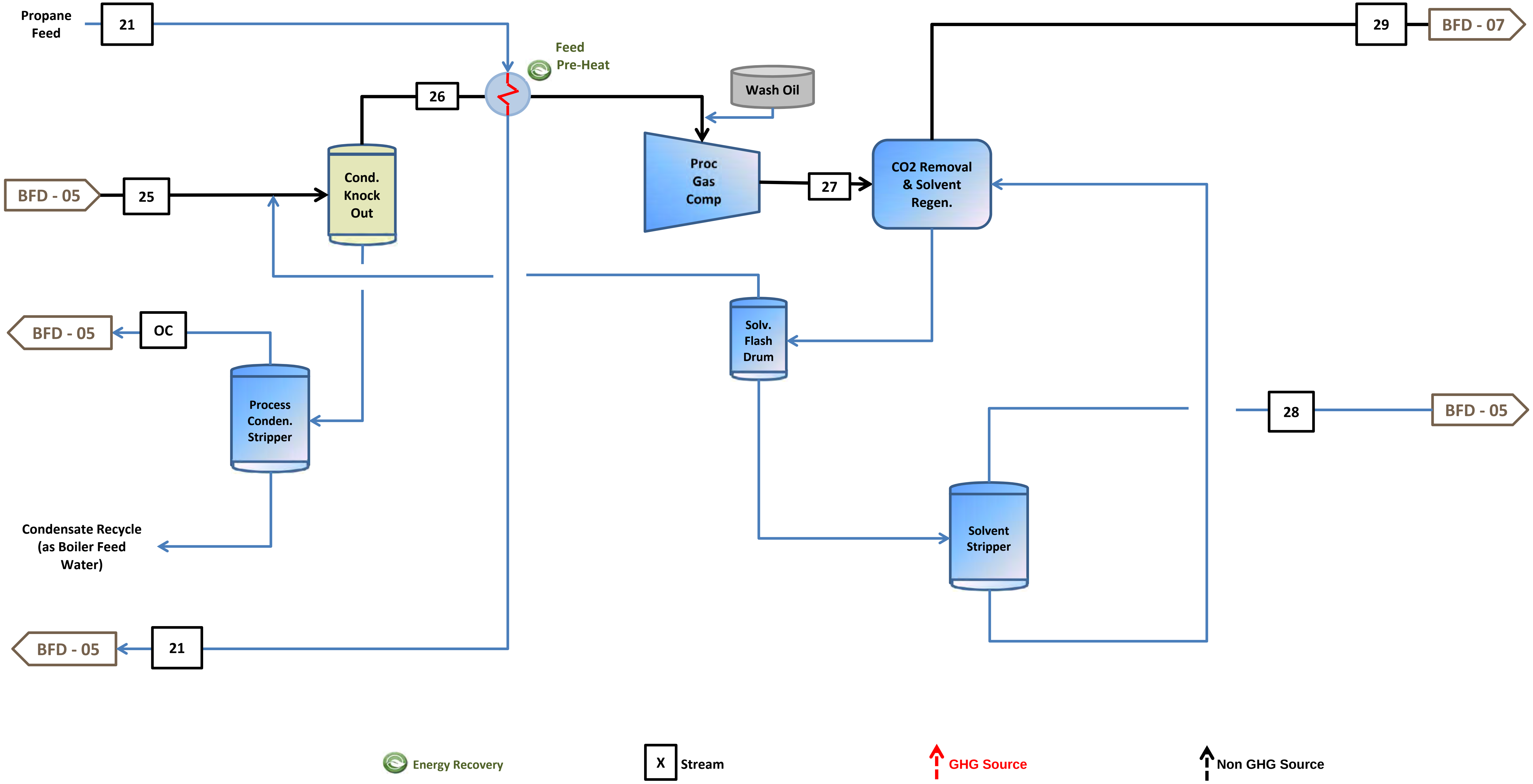
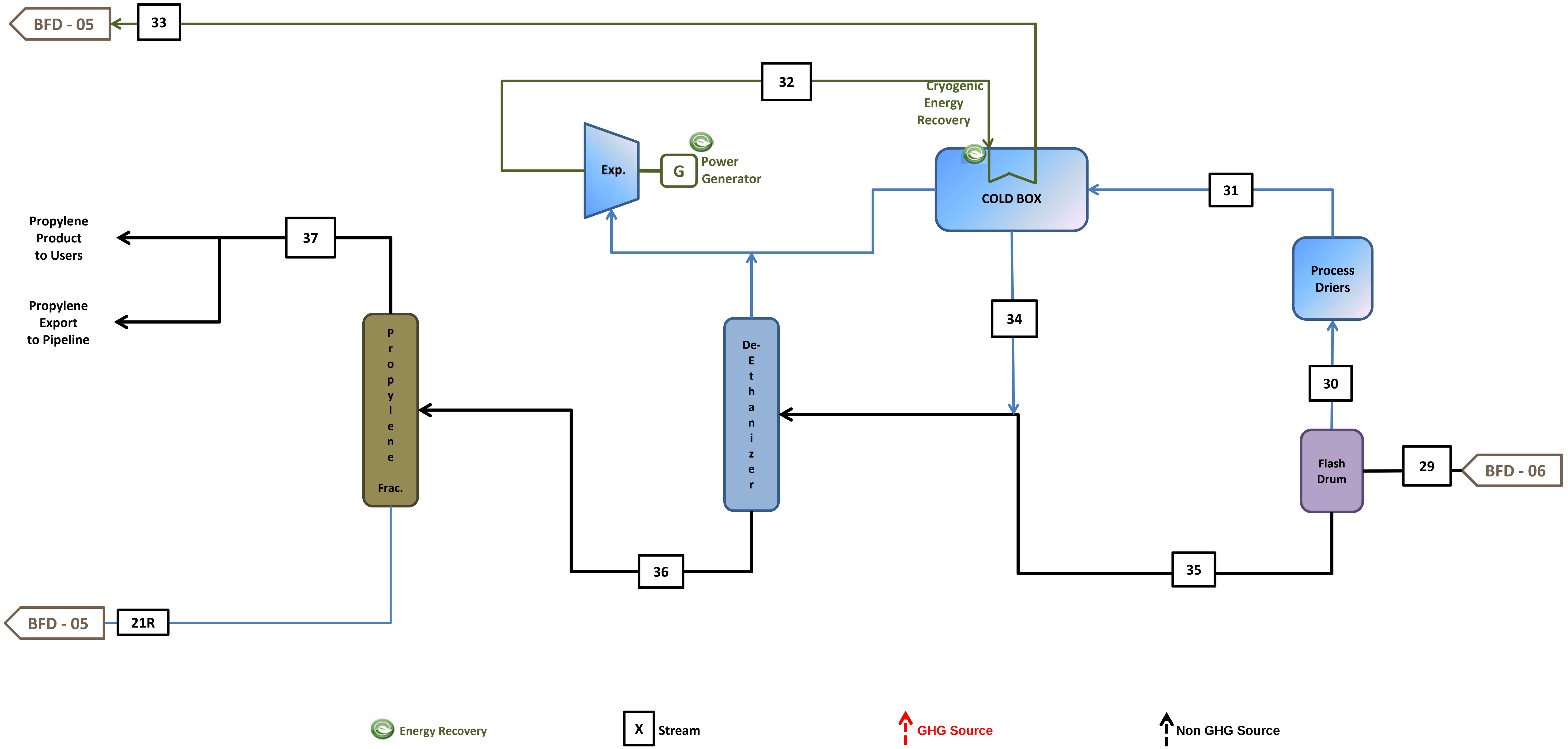
Olefins Expansion

Propane Dehydrogenation (PDH) Plant BFD - 06



Formosa Plastics Corporation
Point Comfort, Texas
Olefins Expansion

Propane Dehydrogenation (PDH) Plant BFD - 07



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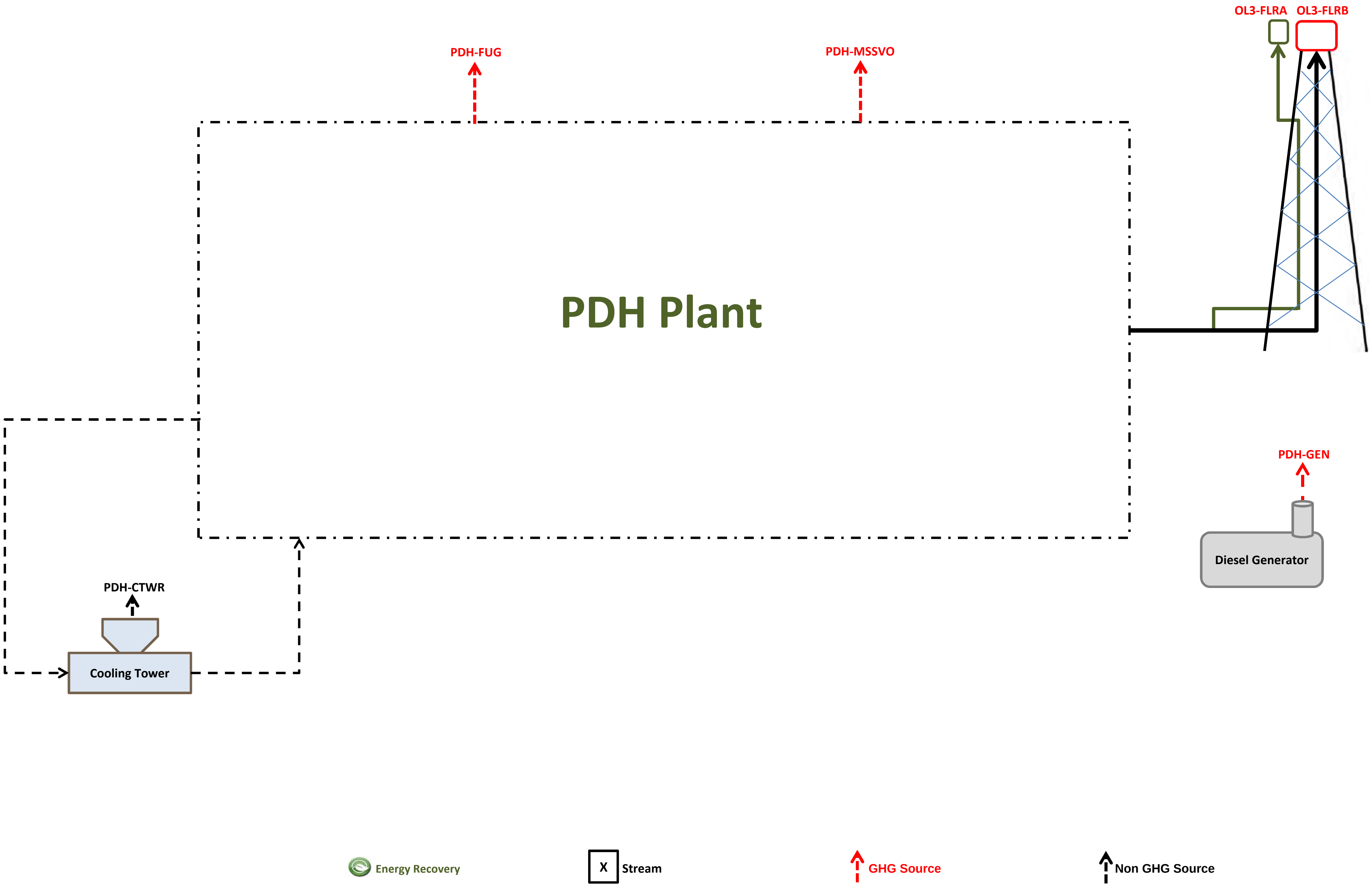
Olefins Expansion

Propane Dehydrogenation (PDH) Plant BFD - 08 (supporting systems)



4.0 GHG EMISSION CALCULATIONS

This section provides a description of the methods used to estimate GHG emissions from the proposed Olefins 3 plant GHG emission units. It should be noted that FPC TX Olefins 3 plant is subject to Subpart X of the GHG MRR which employs a plant-wide carbon balance to calculate emissions of GHGs from the Olefins 3 plant. The Olefins 3 plant and PDH unit include non-combustion emission sources which are not addressed by Subpart X or any other Subpart. For this permit application, individual emission source calculations are required; therefore, the plant-wide carbon balance approach in Subpart X is not an appropriate calculation methodology for this permit application.

GHG emissions were estimated using the most appropriate source-specific emission calculation methodologies available in EPA's GHG Mandatory Reporting Rule (GHG MRR), 40 CFR 98. For each source type, either the applicable methodology or most appropriate methodology (based on the source type) was selected from Subparts C, Y or W of the GHG MRR. The following provides an explanation of calculation methodologies by source type. A summary of GHG emissions, detailed emission calculations and supporting information can be found in Appendix A.

4.1 GHG EMISSIONS FROM NATURAL GAS COMBUSTION SOURCES

Natural gas is used as fuel for the flare pilots and as a startup fuel in the Olefins 3 plant furnaces and the PDH unit steam boilers and reactors. GHG emission calculations for the natural gas-fired combustion units are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart C – Stationary Fuel Combustion Sources.[4]

$$CO_2 = 1\ x\ 10^{-3} x\ Fuel\ x\ HHV\ X\ EF \quad \text{(EQ. C-1)}$$

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[4] 40 CFR 98, Subpart C – *General Stationary Fuel Combustion Sources*

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type, metric tons/yr

Fuel = Volume of fuel combusted per year, standard cubic feet/yr, based on the maximum rated equipment capacity and maximum hours of operation (8,760 hours/yr)

EF = Emission factor for natural gas from table C-1

HHV = default high heat value of fuel, from table C-1

0.001 = conversion from kg to metric tons

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.[5] The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

4.2 GHG EMISSIONS FROM FUEL GAS AND PDH REGNERATION GAS COMBUSTION

GHG emission calculations for the fuel gas and PDH regeneration gas combustion are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart C – Stationary Fuel Combustion Sources.[6]

$$CO_2 = \frac{44}{12} \times Fuel\ x\ CC\ X\ \frac{MW}{MVC} \times 0.001 \quad \text{(EQ. C-5)}$$

Where:

CO_2 = Annual CO_2 mass emissions for the specific fuel type, metric tons/yr

Fuel = Volume of gas combusted per year, standard cubic feet/yr, based on the maximum rated equipment capacity and maximum hours of operation (8,760 hours/yr)

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

[6] 40 CFR 98, Subpart C – *General Stationary Fuel Combustion Sources*

CC = Annual average carbon content of the gas (kg C per scf), obtained from the estimated gas composition

MW = Annual average molecular weight of fuel (kg/kg-mol), obtained from the estimated gas composition

MVC = molar volume conversion factor = 849.5 scf/kg-mol @ std. conditions

0.001 = conversion from kg to metric tons

In accordance with the Tier 3 fuel calculation methodology in 40 CFR 98, Subpart C, 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[7] and annual heat release for fuel gas combustion. The global warming potential factors used to calculate carbon dioxide equivalent (CO_2e) emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.

4.3 GHG EMISSIONS FROM DECOKING

GHG emissions from cracking furnace decoking are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart Y – for process vents[8].

$$\boldsymbol{E = VR \times MF \times \frac{MW}{MVC} \times 0.001} \quad \textbf{(EQ. Y-19)}$$

Where:

E = GHG mass emissions emitted from the process vent, metric tons/yr

VR = Volumetric flow of process vent gas during venting, standard cubic feet/yr, based on engineering estimate and maximum frequency of furnace decoking

MF = mole fraction of GHG in process vent stream, based on engineering estimate

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

[8] 40 CFR 98, Subpart Y – *Petroleum Refineries*

MW = molecular weight of GHG (kg/kg-mol)

MVC = molar volume conversion factor = 849.5 scf/kg-mol @ std. conditions

0.001 = conversion from kg to metric tons

4.4 GHG EMISSIONS FROM MAPD REGENERATION VENT

GHG emissions from the regeneration vent are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart Y – for process vents.

$$\boldsymbol{E = VR \times MF \times \frac{MW}{MVC} \times 0.001} \quad \textbf{(EQ. Y-19)}$$

Where:

E = GHG mass emissions emitted from the process vent, metric tons/yr

VR = Volumetric flow of process vent gas during venting, standard cubic feet/yr, from process design data

MF = mole fraction of GHG in process vent stream, from process design data

MW = molecular weight of GHG (kg/kg-mol)

MVC = molar volume conversion factor = 849.5 scf/kg-mol @ std. conditions

0.001 = conversion from kg to metric tons

4.5 GHG EMISSIONS FROM FLARES

GHG emission calculations for flares are calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart Y – Petroleum Refineries[9], equation no. Y-1a.

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[9] 40 CFR 98, Subpart Y – *Petroleum Refineries*

$$\boldsymbol{CO_2 = 0.98 \times \frac{44}{12} \times Flare\ x\ CC\ X\ \frac{MW}{MVC} \times 0.001} \quad \textbf{(EQ. Y-1a)}$$

Where:

CO_2 = Annual CO_2 mass emissions, metric tons/yr

Flare = Volume of flare gas combusted per year, standard cubic feet/yr, from process design data

CC = Annual average carbon content of flare gas (kg C per scf), from engineering estimate of waste gas composition

MW = Annual average molecular weight of flare gas (kg/kg-mol) from engineering estimate of waste gas composition

MVC = molar volume conversion factor = 849.5 scf/kg-mol @ std. conditions

0.001 = conversion from kg to metric tons

0.98 = flare combustion efficiency

$$\boldsymbol{CH_4 = CO_2 \times (EF_{CH4} \div EF) + CO_2 \times \left(\frac{0.02}{0.98}\right) \times \frac{16}{44} \times f_{CH4}} \quad \textbf{(EQ. Y-4)}$$

Where:

CH_4 = Annual CH_4 mass emissions, metric tons/yr

CO_2 = Annual CO_2 mass emissions, metric tons/yr

EF_{CH4} = CH_4 emission factor for Petroleum Products from Table C-2 of 40 CFR 98 Subpart C = 3.0E-03 (kg CH4/MMBtu)

EF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

0.02/0.98 = Adjustment factor for flare combustion efficiency

16/44 = Correction factor for the ratio of the molecular weight of CH_4 to CO_2

f_{CH4} = Weight fraction of carbon in the flare gas that is contributed by methane (kg CH4/kg C); default is 0.4.

$$\boldsymbol{N_2O} = \boldsymbol{CO_2} \times (\boldsymbol{EF_{N2O}} \div \boldsymbol{EF}) \quad \textbf{(EQ. Y-5)}$$

Where:

N_2O = Annual N_2O mass emissions, metric tons/yr

CO_2 = Annual CO_2 mass emissions, metric tons/yr

EF_{N2O} = N_2O emission factor for Petroleum Products from Table C-2 of 40 CFR 98 Subpart C = 6.0E-04 (kg CH4/MMBtu)

EF = Default CO_2 emission factor for flare gas of 60 kg CO_2/MMBtu (HHV basis)

4.6 GHG EMISSIONS FROM NATURAL GAS AND FUEL GAS PIPING FUGITIVES

GHG emission calculations for natural gas and fuel gas piping component fugitive emissions are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[10] The concentrations of CH_4 and CO_2 in the natural gas are based on a typical natural gas analysis. Since the CH_4 and CO_2 content of plant fuel gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as a worst-case estimate. Actual CH_4 and CO_2 concentrations in the fuel gas are expected to be lower than that of natural gas. Although audio/visual/olfactory (AVO) inspections are being proposed as BACT for this source (see Section 6.9.5) no control efficiency credits were taken for AVO monitoring. The global warming potential factors used to calculate CO_2e emissions are based on Table A-1 of Mandatory Greenhouse Gas Reporting Rules.[11]

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[10] *Default Whole Gas Emission Factors for Onshore Petroleum and Natural Gas Production*, 2012 Technical Corrections to 40 CFR Part 98, Subpart W, Table. W-1A.

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

4.7 GHG EMISSIONS FROM FUEL OIL FIRED ENGINES

GHG emissions from the diesel-fired emergency engines were calculated using the engine's maximum rated horsepower, fuel consumption rate (Btu/hp-hr), maximum annual operation and the diesel fuel GHG emission factors from Tables C-1 and C-2 of 40 CFR 98 Subpart C listed below. The maximum annual operation is 100 hours per year per NSPS Subpart IIII[12].

Emission factor for Distillate Fuel Oil No. 2 from 40 CFR 98, Subpart C:

Default CO_2 emission factor (kg CO_2/mmBtu) = 73.96

4.8 GHG EMISSIONS FROM MSS ACTIVITIES

GHG emissions from waste gas flaring (products of combustion) are calculated using the same methodology described in Section 4.5. Emissions from uncombusted waste gas from the flare are calculated by applying the GHG composition (weight fraction) in the stream to the quantity of waste gas routed to the flare and then applying the percentage of gas not combusted (100% minus the DRE).

GHG emissions from vessel openings were calculated by applying each stream's GHG composition (weight fraction) to the quantity of gas vented to atmosphere during vessel opening.

A summary of the total GHG emissions from MSS activities is included in Appendix A.

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[12] 40 CFR 60, Subpart IIII

5.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Since the Point Comfort expansion project[13] emissions increase of GHG is greater than 75,000 ton/yr of CO_2e, PSD is triggered for GHG emissions. The emissions netting analysis, which includes all 2012 Expansion Project GHG emission sources, is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F found in Appendix B. Note that there are some existing project emission sources associated with the Olefins 3 plant that are existing and, as such, the contemporaneous GHG emission changes associated with the project are shown in the tables.

Please note that, although separate permits are being requested and three separate permit applications have been submitted, the project increase shown here represents emissions from all 2012 Expansion Project GHG emission sources.

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[13] Includes emission sources from Olefins 3 plant, LDPE plant and combined cycle turbines.

6.0 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.[14]

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.[15] 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

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[14] 40 CFR § 52.21(b)(12.)

[15] EPA, *PSD and Title V Permitting Guidance for Greenhouse Gases*, p. 18 (March 2011).

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 divided this analytical process into the following five steps:

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

This evaluation is generally performed individually for each GHG emission source which are addressed in subsections 6.2 onward. One control technology, Carbon Capture and Sequestration (CCS), could be a potential control technology for multiple emissions sources associated with the 2012 Expansion Project. Therefore, before presenting the BACT evaluation for the individual Olefins Expansion GHG emission sources, the first subsection 6.1, will present the BACT evaluation for CCS as a potential control technology.

6.1 BACT FOR CARBON CAPTURE AND SEQUESTRATION

FPC TX addresses the potential to capture GHG emissions that are emitted from Carbon Capture and Sequestration (CCS) candidate sources associated with the 2012 Expansion Project listed below (plant names in parenthesis):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE)

The EPA five step top down BACT evaluation for this potential control technology options is provided in Appendix C. As shown in that analysis, CCS is not commercially available, not technically feasible, and also economically unreasonable. Therefore, CCS is not included as a BACT option for any of the emissions sources associated with the 2012 Expansion Project.

6.2 BACT FOR THE CRACKING FURNACES

6.2.1 Step 1: Identify All Available Control Technologies

Other than CCS, addressed in Section 6.1, the primary GHG control options available are selection of energy efficient design options to maximize thermal efficiency and implementation of select operation and maintenance procedures to ensure energy-efficient operation of the furnace on an ongoing basis.

The following discussion lists those design elements and operating and maintenance practices that have been considered and selected to maximize energy efficiency. These individual elements are not being individually considered as BACT control options, rather overall unit energy-efficient design and operation is considered the BACT option. The individual elements' effects on overall unit energy efficiency are reflected in the proposed holistic energy efficiency-based BACT limit in Step 5, which limits the maximum furnace exhaust temperature: a metric of overall furnace thermal efficiency. By selecting each of the available design options related to energy efficiency, FPC TX is proposing a maximum furnace exhaust temperature that is notably lower than comparable furnaces operating and proposed in olefins production units.

6.2.1.1 Furnace Design Background

The cracking furnaces will be designed to maximize energy efficiency and heat recovery. The following section describes the detailed furnace design and those typical furnace design elements that bolster energy efficiency. Specific design elements that were considered and selected are addressed in the next subsection.

Furnace Section

The primary heat transfer for the cracking reaction occurs through the radiant section tubes. The radiant tubes will be located in the center of the firebox to minimize the shadowing effect of adjacent radiant tubes. The tubes will be oriented vertically in the center of the firebox with burners on the sides. This allows for more uniform heat transfer and minimizes chances for coke formation inside the tubes. Furthermore, the radiant tubes will be equipped with sonic flow venturis at the inlet to each tube to promote uniform flow which will result in uniform tube heating and successful cracking of the process feed.

The furnace radiant section will also be designed to reduce air infiltration at the radiant tube exit and entry points in the firebox. The number of tube entry and exit points will be minimized and each of these points will be sealed to prevent heat loss. The proposed tube configuration will allow for increased radiant heat transfer and maximum thermal efficiency in the radiant section. The firebox is designed to sustain a nominal operating temperature of approximately 2,000 degrees F. Thermal insulation (high temperature brick and ceramic) will be utilized along the walls of the firebox to minimize heat loss and maximize reflection of radiant heat back to the radiant tubes. Minimizing heat loss results in lower fuel consumption to maintain a specified firebox operating temperature and thus lower GHG emissions.

Burners

High efficiency burners, designed for optimum combustion of the hydrogen-rich fuel gas, will be installed in the firebox on both sides of the radiant tubes. The burners will be designed and operated with minimum excess air to maximize combustion efficiency. Prior to installation, the burners will be tested in a burner vendor facility to verify optimal design and fabrication. Computational flow dynamics modeling of the burner arrangement and burner flame pattern will be utilized to ensure proper firebox operation. Once installed in the cracking furnaces and operational, the burners will be inspected routinely to confirm the correct flame pattern/profile is achieved.

Convection Section

The convection section receives hot flue gases from the firebox and uses them for heat recovery across several convection tubebanks containing process fluids. These convection tubes, in waste heat recovery service, will preheat boiler feedwater, superheat high pressure steam and preheat process feed gas. A maximum amount of thermal energy is recovered in the convection section while still maintaining the required flue gas temperature for the selective catalytic reduction (SCR) reaction for NO_X reduction. The SCR catalyst bed is located in the convection section.

The convection section in the cracking furnace is specifically designed to be located in a position off-set from the firebox to prevent radiant overheating in the convection section. Off-setting the location of the convection section reduces the risk of unplanned startup and shutdowns as a result of overheating or reduced heat transfer and thus maximizes overall thermal efficiency.

The area located in the furnace convection section off-set is also referred to as the transition section. In this section the flue gases exiting the firebox make ninety degree turns before entering the convection section. The transition section will be designed to specifically reduce the risk of flue gas channeling. The convection section's first tubeset will be located at a distance above the transition section to allow for properly developed flue gas flow to contact the tubes, thus maximizing heat transfer and energy recovery.

The convection section will feature refractory insulation along the walls, similar to the radiant section, to minimize heat loss and meet American Petroleum Institute's recommendations for external skin temperature. The convection section tubes will be designed for a triangular arrangement between rows of tubes to maximize convective heat transfer to each tubeset. The ends of each tubeset will be designed with refractory flow diverters to prevent flue gas channeling and maximize heat transfer efficiency in the convection section.

Fan

An induced draft fan will be installed on the top of the convection section to pull flue gas upward through the convection section. A damper will be installed and operated on the fan outlet to maintain a draft that produces minimum infiltration of tramp air and provides control of oxygen levels that maximize combustion efficiency in the combustion section of the furnaces.

6.2.1.2 Energy-Efficient Design Elements

The following section lists those specific energy-efficient design options that were considered and selected by FPC TX to maximize furnace energy efficiency.

- Feed Preheating – By preheating the ethane/steam feed mixture in the convection section prior to cracking, less fuel firing is required to initiate the cracking process. FPC TX estimates that approximately 48 MMBtu/hr of thermal energy will be recovered by implementing this option.
- Economizer – Use of heat exchanger to recover heat from the exhaust gas to preheat incoming steam drum feedwater will maximize thermal efficiency. FPC TX estimates that approximately 25 MMBtu/hr of thermal energy will be recovered by implementing this option.

  Steam drum – use of heat exchangers (quench exchangers) to recover heat from the radiant section flue gas and generate high pressure steam. This heat recovery creates beneficial steam that can be used to create mechanical energy in other equipment. FPC TX estimates that approximately 32 MMBtu/hr of thermal energy will be recovered by implementing this option.
- Condensate recovery – Return of hot condensate for use as feedwater to the steam drum. Use of hot condensate as feedwater results in less heat required to produce steam, thus improving thermal efficiency. FPC TX estimates that approximately 11 MMBtu/hr of thermal energy will be recovered by implementing this option.
- Additional boiler feed water (BFW) coil bank in convection section - Conventional furnace designs include a single BFW preheat section in the upper portion of the convection section to recover waste heat from flue gases leaving the radiant section. The convection section of the Olefins 3 funaces have been designed with an additional bank of BFW coils/tube to provide maximum heat recovery from the flue gases. As the furnace gets older and efficiency (due to coil fouling) becomes an issue, this design option ensures continued heat recovery and efficiency greater than conventional industrial furnaces. FPC TX estimates that including this design option will achieve an additional 5 MMBtu/hr (approximately) of heat recovery.

- Lower BFW supply temperature - The BFW temperature being supplied to the BFW coils will enter the heat recovery section at a temperature of approximately 160 F to ensure maximum heat absorption.

By selecting each of these energy efficiency-related design options (design option A), FPC TX's furnace is being designed with a notably low stack exit temperature, which indicates that the units are designed for maximal heat recovery. A numeric energy efficiency-based BACT limit and benchmarking against other sources is addressed in Step 5.

6.2.1.3 Operating and Maintenance Elements Relating to Energy Efficiency

The following operating and maintenance practices were considered and selected to maximize propylene yield by improving furnace efficiency.

- Firing hydrogen-rich (low carbon) fuel gas as the primary fuel.
- Oxygen trim control – Monitoring oxygen concentration in the flue gas adjustment of inlet air flow will assist in maximizing thermal efficiency. The furnaces will be equipped with oxygen analyzers in both the stack and the arch (between the radiant and convection sections). Typically, excess oxygen levels of 3 to 5 percent are optimal for a good combustion profile. The furnace combustion system features air adjustment dampers at the burners and an adjustment damper at the furnace draft fan. Both damper systems are designed for both automatic and manual (operator) control capability.
- Periodic decoking of radiant section heat transfer surfaces to remove coke formation in furnace's radiant coils will improve heat transfer through the tube walls and improves thermal efficiency.
- Periodic furnace tune-up – The furnace will receive periodic inspection and maintenance (no less than once every 24 months) to maintain optimal thermal efficiency.

6.2.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.2.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.2.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.2.5 Step 5: Select BACT

FPC TX proposes the selection of all available energy-efficient design options and operational/maintenance practices presented in Step 1 as BACT for the cracking furnaces. Since the proposed energy efficiency design options, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, FPC TX is proposing a BACT limit for each furnace which takes into consideration the operation, variability and interaction of all these energy efficient features in combination. A holistic BACT limit which accounts for the ultimate performance of the entire unit was chosen, rather than individual independent subsystem performance. Otherwise, monitoring and maintaining energy efficiency would be un-necessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

FPC TX proposes a numerical energy efficiency-based BACT limit for maximum exhaust gas temperature, as this is a direct indicator of energy-efficiency. FPC TX proposes that, for purposes of an enforceable BACT limitation a numerical energy efficiency-based BACT limit for maximum exhaust gas temperature of 290 ºF averaged on a 365-day rolling average basis. FPC TX will monitor the furnaces' flue gas exhaust temperature in accordance with permit conditions.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for gas-fired cracking furnaces and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed in other

GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

BASF FINA - NAFTA Region Olefins Complex

The application for the BASF FINA Olefins Complex expansion was submitted on May 17, 2011 to EPA Region 6 and a final GHG permit was issued on August 24, 2012. This permit authorizes the addition of one new cracking furnace with an average annual heat input of 490.7 MMBTU/hr. The permit lists a GHG BACT limit of flue gas exhaust temperature less than or equal to 309 ºF on a 365-day rolling average basis.

FPC TX's proposed BACT limit (maximum exhaust gas temperature) is less than the value listed in the BASF FINA permit. As such, its cracking furnaces will meet an energy efficiency-based numeric BACT limit that is equal or better than this similar source.

Equistar Channelview Olefins I and II Expansions

The Equistar Olefins I and II permit applications were submitted to EPA Region 6 on September 23, 2011. These applications request authorization of four cracking furnaces, with a capacity of approximately 350 MMBtu/hr each. The permit applications propose several energy efficient design elements, low carbon fuels and proper furnace operation as BACT, however no numeric BACT limit was proposed.

FPC TX is proposing the same or similar BACT design and operation options as proposed by Equistar. In addition, as described specifically in Step 1, FPC TX is proposing an energy efficiency-based numeric BACT limit which establishes an enforceable limit for GHG emissions from the cracking furnaces.

Equistar La Porte – Olefins Expansion

The Equistar La Porte permit application was submitted to EPA Region 6 in September, 2011 and revised on May 2012. These applications request authorization of two cracking furnaces, with a capacity of more than 400 MMBtu/hr each. The permit application proposes several energy efficient design elements, low carbon fuel selection and best operational practices as

BACT. Furnace thermal efficiency of 93+% is targeted with the proposed design, however a numeric BACT limit and associated monitoring were not proposed.

FPC TX is proposing the same or similar BACT design and operation options as proposed by Equistar. In addition, as specifically described in Step 5, FPC TX is proposing an energy efficiency-based numeric BACT limit which establishes an enforceable limit for GHG emissions from the cracking furnaces.

ExxonMobil Baytown Olefins Plant

The Baytown Olefins Plant permit application was submitted to EPA Region 6 on May 21, 2012. This application requests authorization of eight cracking furnaces with an annual average firing rate of approximately 570 MMBtu/hr each. The application proposes energy efficient design, good operation and maintenance practices and low carbon fuels as BACT.

FPC TX is proposing the same or similar BACT design and operation options as ExxonMobil. In addition, as specifically described in Step 5, FPC TX is proposing an energy efficiency-based numeric BACT limit which establishes an enforceable limit for GHG emissions from the cracking furnaces.

INEOS USA LLC – Olefins Expansion

On February 2012, INEOS USA LLC (INEOS) submitted a revised GHG permit application to EPA Region 6 requesting the authorization on one additional cracking furnace, rated at 495 MMBtu/hr. The final GHG permit was issued on October 5, 2012. The permit lists a numeric GHG BACT limit for maximum exhaust gas temperature of 340 ºF.

In addition to proposing energy efficiency design and operation BACT options (specifically described in Step 1), FPC TX's proposed BACT limit presented in Step 5 is less than the value listed in the INEOS permit application. As such, FPC TX's cracking furnaces will meet an energy efficiency-based numeric BACT limit that is equal or better than the INEOS furnace.

Chevron Phillips Chemical Company LP – Cedar Bayou Plant, New Ethylene Unit

In December 2011, Chevron Phillips submitted a GHG permit application to EPA Region 6 requesting authorization of eight new ethylene cracking furnaces with a maximum capacity of 500 MMBtu/hr, each. The application proposes energy efficient design, low carbon fuels and good combustion practices as BACT.

FPC TX is proposing the same or similar BACT design and operation options as Chevron Phillips. In addition, as specifically described in Step 5, FPC TX is also proposing an energy efficiency-based numeric BACT limit which establishes an enforceable limit for GHG emissions from the cracking furnaces.

6.3 BACT FOR DECOKING VENTS

6.3.1 Step 1: Identify All Available Control Technologies

Decoking is a process of removing coke deposits from the interior of process tubes in the furnace. This is a combustion process with CO and CO_2 being a product of that combustion. The gases are emitted via a drum that is used to remove particulates.

Coke accumulates in the furnace tubes and reduces heat transfer efficiency so minimizing coke formation is optimal for energy efficiency of the furnace and maximum ethylene yield in addition to reducing the required frequency of decoking events. There are no available technologies that have been applied to furnace decoke drums to control CO_2 emissions. As described specifically in Section 6.2.1, proper design and operation of the furnaces to minimize coke formation/ frequency of decoking events is the only technically feasible means of minimizing GHG emissions.

FPC TX proposes to limit the frequency of furnace decoking for all Olefins 3 furnaces to no more than 108 events (all furnaces) per rolling-12 month period, which is the basis for the decoking emission calculations presented in Section 4. This proposed permit limit does not include decoking events related to emergency shutdowns or unforeseen, unplanned maintenance events.

6.3.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.3.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.3.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.3.5 Step 5: Select BACT

Minimizing the formation of coke on the furnace tubes through proper furnace design and operation (as specifically described in Section 6.2) is BACT for Greenhouse Gas emissions. FPC TX proposes a numeric BACT limit of 108 decoking events per rolling 12-month period (for all Olefins 3 furnaces). This proposed permit limit does not include decoking events related to emergency shutdowns or unforeseen, unplanned maintenance events. FPC TX proposes to monitor the frequency of decoking events using operational records.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for decoking and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

BASF FINA - NAFTA Region Olefins Complex

The BASF permit lists a GHG BACT limit for furnace decoking of 13 times on a rolling 12-month basis. FPC TX's proposed BACT limit for furnace decoking of 108 times per rolling 12-month period or all furnaces is essentially equivalent to an average of 12 decoking events per furnaces

(9 total), which is less than the value listed in the BASF FINA permit. As such, the proposed energy efficiency-based numeric BACT limit that is equal or better than this similar source.

Equistar Channelview Olefins I and II Expansions

The Equistar permit applications propose proper furnace design and operation to limit coke as BACT for decoking emissions. FPC TX is proposing BACT that is similar to, or the same as the one proposed by Equistar and is providing a specific description of proposed furnace design and operation (Section 6.2). As specifically described in Step 5, FPC TX is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from furnace decoking.

Equistar La Porte – Olefins Expansion

The Equistar permit application proposes proper furnace design and operation to limit coke formation as BACT. The application also mentions limiting excess oxygen, however a numeric BACT limit and associated monitoring were not proposed. FPC TX is proposing BACT that is similar to, or the same as the one proposed by Equistar and is providing a specific description of proposed furnace design and operation (Section 6.2). As specifically described in Step 5, FPC TX is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from furnace decoking.

ExxonMobil Baytown Olefins Plant

The ExxonMobil permit application proposes proper furnace design and operation to minimize coke formation and limiting air during decoking as BACT for decoking emissions. FPC TX is proposing BACT that is similar to, or the same as the one proposed by ExxonMobil and is providing a specific description of proposed furnace design and operation (Section 6.2); however, FPC TX is not proposing a limitation on air during furnace decoking. FPC TX is, instead, proposing an enforceable numeric BACT limit (described in Step 5) which establishes an enforceable limit for GHG emissions from furnace decoking.

INEOS USA LLC – Olefins Expansion

The INEOS permit lists a numeric GHG BACT limit for the duration of decoking of 420 hours per 12-month period to be demonstrated by monitoring the actual duration of decoking events. FPC

TX's proposed BACT limit of 108 events per year (all furnaces) is comparable to the proposed INEOS BACT. As such, FPC TX's decoking operations will meet a numeric BACT limit that is comparable to this similar source.

Chevron Phillips Chemical Company LP – Cedar Bayou Plant, New Ethylene Unit

The ChevronPhillips application proposes good furnace operation and design to limit coke formation as BACT. FPC TX is proposing the same or similar BACT as ChevronPhillips and is providing a specific description of proposed furnace design and operation (Section 6.2). As described in Step 5, FPC TX is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from furnace decoking.

6.4 BACT FOR MAPD REGENERATION VENT

6.4.1 Step 1: Identify All Available Control Technologies

CCS technology as an add-on control for the MAPD regeneration vent was considered, however given the extremely intermittent nature of this vent (few regeneration cycles per year), it was not considered to be a technically feasible candidate CCS source.

There are no other applicable technologies for controlling GHG emissions from the MAPD regeneration vent. The MAPD regeneration vent's CO2e emissions (estimated at less than 30 tpy) represent less than 0.001% of the project's GHG emissions; therefore, this source is an inherently low-emitting GHG emission source. As such, FPC TX is not proposing a numeric energy efficiency-based limit for this source.

6.4.2 Step 2: Eliminate Technically Infeasible Options

The MAPD regeneration vent is intermittent and is not a technically feasible candidate source for CCS technology (detailed CCS technology BACT evaluation provided in Appendix C). No other GHG BACT options are being eliminated.

6.4.3 Step 3: Rank Remaining Control Technologies

FPC TX is not eliminating any of the available BACT options; therefore, ranking is not required.

6.4.4 Step 4: Evaluate Most Effective Controls and Document Results

FPC TX is not eliminating any of the available BACT options; therefore, effectiveness evaluation is not required.

6.4.5 Step 5: Select BACT

The MAPD regeneration vent's CO2e emissions (estimated at less than 30 tpy) represent less than 0.001% of the project's GHG emissions; therefore, this source is an inherently low-emitting GHG emission source. As such, FPC TX is not proposing a numeric energy efficiency-based limit for this source.

6.5 BACT FOR STEAM BOILERS

6.5.1 Step 1: Identify All Available Control Technologies

Other than CCS, addressed in Section 6.1, the primary GHG control options available are selection of energy efficient design options to maximize thermal efficiency and implementation of select operation and maintenance procedures to ensure energy-efficient operation of the furnace on an ongoing basis.

The following discussion lists those design elements and operating and maintenance practices that have been considered and selected to maximize energy efficiency. These individual elements are not being individually considered as BACT control options, rather overall unit energy-efficient design and operation is considered the BACT option. The individual elements' effects on overall unit energy efficiency are reflected in the proposed holistic energy efficiency-based BACT limit in Step 5.

6.5.1.1 Energy-Efficient Design Elements

The following section lists those specific energy-efficient design options that were considered and selected by FPC TX to maximize boiler energy efficiency.

- Use of hydrogen-rich fuel gas – use of a hydrogen-rich (low carbon) fuel gas which is produced as a product in the ethane cracking process results in less CO_2 emissions as compared to firing of natural gas.
- Economizer – use of a heat exchanger to recover heat from the exhaust gas to preheat incoming boiler feedwater and maximize thermal efficiency. The flue gas leaving the boiler has a considerable amount of energy. By using an economizer (heat trap) downstream of the boiler to convert the energy in the flue gas to preheating the feedwater entering the boiler, the boiler efficiency is increased 4-5%. This equates to a fuel savings of approximately 109,000 MMBtu/yr per boiler, or a GHG reduction of 45,000 tpy CO_2e per furnace (4,050,000 tpy total).
- Condensate recovery – Return hot condensate for use as boiler feedwater reducing preheated feedwater required and improving thermal efficiency. By returning hot condensate as boiler feed, the feedwater contains more energy when it enters the boiler requiring less fuel to be burned to change it into steam.

6.5.1.2 Operating and Maintenance Elements Relating to Energy Efficiency

The following operating and maintenance practices were considered and selected to improve boiler efficiency.

- Oxygen trim control – monitoring of oxygen concentration in the flue gas and adjusting the inlet air flow to maximize thermal efficiency. The burner efficiency requires a designed amount of excess air to thoroughly combust all of the fuel. Any amount of air used above this design value is a heat loss of energy that goes up the stack. For every 10% of excess air used above design values the boiler will require 1% more fuel to be burned to make the same amount of steam flow. Oxygen trim allows the design excess air levels to maintained at all times and minimize fuel usage. For example, a fluctuation of 5% of additional excess air would require an additional 10,950 MMBtu/yr per boiler, or additional emissions of 4,580 tpy CO_2e per boiler (41,220 tpy total).
- Periodic Boiler Tune-up – The boilers are subject to the Boiler MACT (40 CFR 63 Subpart DDDDD) which requires an annual tune-up. These annual tune-ups will promote efficient operation of the boiler and will include the following elements:

- burner inspection and cleaning or replacement components as necessary,
- inspection of flame pattern and burner adjustments as necessary to optimize the flame pattern,
- inspection of the system controlling the air-to-fuel ratio
- optimize total emissions of carbon monoxide, and
- measure the concentrations carbon monoxide and oxygen in the exhaust before and after the adjustments are made.

By selecting each of these energy efficiency-related design options and operational and maintenance practices, FPC TX's boilers are expected to have a minimum thermal efficiency of 78% (for the life of the boiler) as calculated on a rolling 12-month basis using the following equation:

$$Boiler\ Efficiency\ = \frac{(steam\ flow\ rate\ x\ steam\ enthalpy) - (feedwater\ flowrate\ x\ feedwater\ enthalpy)}{Fuel\ firing\ rate\ x\ Gross\ Calorific\ Value\ (GCV)} * 100$$

Another design option (design option B) available does not include an economizer on the boilers and thus yields a unit thermal efficiency of 75% or less; therefore, FPC TX's proposed energy-efficient design is best-in-class. A numeric energy efficiency-based BACT limit and benchmarking against other sources is addressed in Step Discussion of a selected energy efficiency-based BACT limit is included in Step 5.

6.5.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.5.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.5.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.5.5 Step 5: Select BACT

FPC TX proposes the selection of all available energy-efficient design options and operational/maintenance practices presented in Step 1 as BACT for the steam boilers. Since the proposed energy efficiency design options, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, FPC TX is proposing a BACT limit for each boiler which takes into consideration the operation, variability and interaction of all these energy efficient features in combination. A holistic BACT limit which accounts for the ultimate performance of the entire unit was chosen, rather than individual independent subsystem performance. Otherwise, monitoring and maintaining energy efficiency would be un-necessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

FPC TX proposes a numerical energy efficiency-based BACT limit of 78% minimum thermal efficiency per boiler on a rolling 12-month basis calculated using the equation shown in Step 1.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for gas-fired boilers and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

INVISTA – Victoria Site, West Powerhouse

On March 12, 2012 INVISTA submitted a permit application to EPA Region 6 requesting modification of existing gas and liquid-fired boilers at its Victoria, Texas plant. The INVISTA application proposes existing energy efficient design options (e.g., economizer, oxygen trim, insulation, condensate return) and operational measures as BACT.

It should be noted that the INVISTA application requests modification to older boilers, while FPC TX is proposing construction of new steam boilers. As such, FPC TX's proposal for a new energy-efficient boiler design as BACT is more energy-efficient than INVISTA's proposed boiler modification. As described in Step 5, FPC TX is also proposing a numeric energy efficiency-based BACT minimum thermal efficiency limit and associated monitoring for ongoing demonstration of compliance.

BASF FINA - NAFTA Region Olefins Complex

The BASF permit authorizes two steam boilers with a maximum design heat input of 425 MMBtu/hr, each. The issued permit lists a GHG BACT limit of 77% minimum thermal efficiency per boiler on a rolling 12-month basis. FPC TX is proposing the same or similar BACT as BASF, including a limit that is greater than (more energy efficient than) the value listed in the BASF FINA permit. As such, its steam boilers will meet an energy efficiency-based numeric BACT limit that is equal or better than this similar source.

6.6 BACT FOR PDH UNIT REACTORS

6.6.1 Step 1: Identify All Available Control Technologies

Other than CCS, addressed in Section 6.1, the primary GHG control options available are selection of energy efficient design options to maximize thermal efficiency and implementation of select operation and maintenance procedures to ensure energy-efficient operation of the furnace on an ongoing basis.

The following discussion lists those design elements and operating and maintenance practices that have been considered and selected to maximize energy efficiency. These individual elements are not being individually considered as BACT control options, rather overall unit energy-efficient design and operation is considered the BACT option. The individual elements' effects on overall unit energy efficiency are reflected in the proposed holistic energy efficiency-based BACT limit in Step 5, which limits the maximum reactor exhaust temperature: a metric of overall furnace thermal efficiency.

6.6.1.1 Reactor Design Background

The reactors will be designed to maximize energy efficiency. The following section describes the detailed reactor design and those typical reactor design elements that bolster energy efficiency. Specific design elements that were considered and selected are addressed in the next subsection.

The first step in the production of propylene from propane occurs in the reactor which is energy intensive due to endothermic dehydrogenation reaction.

The major components of the reactor are
− firebox
− burners
− convection section
− combustion and flue gas fan
− steam drum

The heat contained in the reactor product gas is recovered by a heat exchanger to increase the energy recovery of the PDH unit. Heat recovery from process gas is applied for following purposes:

- Feed / Steam Preheating: Feed / Steam gas is preheated to the maximum extent prior to entering the feed preheating coils in the convection bank.
- Steam generation: Generation of steam to be used as required steam in the dehydrogenation reaction.
- Heat supply to reboilers of the ammonia refrigeration system providing required refrigeration duty to the gas separation, which decreases overall plant emissions.
- Heat supply to the condensate stripper, depropanizer, deeethanizer and CO_2 stripper columns.

To minimize the energy consumption, the reactor furnace is intentionally designed to maximize the energy efficiency in the various components since 35-40% of the energy consumption is for direct heating requirements in the reactor furnace. The furnace design of the reactor will maximize thermal efficiency as described below. Reactor design will incorporate the latest improvement in heat transfer and fluid flow to maximize the energy efficiency and recovery.

Radiant Section

The firebox of a reactor is the main part of the reactor where the dehydrogenation reaction of propane to propylene and hydrogen takes place in catalyst filled vertical tubes. The dehydrogenation process is highly endothermic, so heat must be added to allow dehydrogenation reaction to be continued.

The catalyst filled process tubes are arranged in rows, heat is provided by top fired burners arranged in burner rows between the tube rows to distribute the radiant heat as uniform as possible. This minimizes coke build-up inside the tubes to the largest possible extent. The nature of the dehydrogenation reaction is such that its thermodynamic equilibrium is favored by increasing temperature and decreasing partial pressure. Dilution steam is added as mediator to reduce coke build-up and to reduce the partial pressure of the hydrocarbon phase.

The dehydrogenation reaction takes place at high temperatures. The higher the temperature, the higher the radiant heat transfer (as opposed to conductive or convective heat transfer). The hot firebox radiates heat to the relatively cold radiant tubes for dehydrogenation.

Since the firebox temperature in a reactor furnace is high, it is important to minimize heat loss from the firebox and it is important to have sufficient insulation to reduce the external metal temperatures to meet values recommended by American Petroleum Institute. A combination of high temperature brick and ceramic fiber insulation of sufficient thickness will be used along the walls of the firebox to reduce heat loss and to maximize reflection of radiant heat back to the tubes.

Burners

High efficiency, low-NOx burners will be installed in the reactor box. The burners that will be installed in the reactors will be tested at the burner vendor facility prior to installation and burner design optimized for maximizing efficiency and operability.

Burners will be designed to operate with minimum excess air to maintain high combustion efficiency. The reactor will be equipped with an oxygen analyzer to provide data used in the control of the combustion process. Operation with more than optimum excess air causes energy efficiency losses leading to higher fuel gas consumption. The burners will be designed to operate under the range of fuel gases combusted in the plant including natural gas and plant produced fuel gases.

Convection Section

The hot flue gases conducted out of the fire box using channels in the bottom of the firebox is routed to the convection section. The hot flue gases from the firebox are cooled in several steps to maximize heat recovery and therefore increase overall thermal efficiency of the reactor. In the convection section the heat transfer occurs primarily by convection with hot flue gases transferring heat to the convection tubes which are located horizontally and/or vertically in the convection section. The convection section is located beside the reactor furnace box having an offset with respect to the reactor box using a transition duct to homogenize the flue gases.

The convection bank will have refractory along the walls of sufficient thickness to minimize heat loss from the convection bank walls and to meet American Petroleum Institute recommendations for external skin temperature. The tubes are arranged in such a way that the heat transfer is maximized thus maximizing efficiency.

The selective catalytic reduction (SCR) catalyst bed for reduction of the NOx will be fully integrated into the convection bank. The SCR location is chosen in such a way that the optimum reaction temperature will be achieved, thus leading to the specified NOx emission level.

6.6.1.2 Energy-Efficient Design Elements

The following section lists those specific energy-efficient design options that were considered and selected by FPC TX to maximize reactor energy efficiency.

- Firing hydrogen-rich (low carbon) fuel gas as the primary fuel
- Feed preheating – By selecting feed stream preheating, FPC TX is able to recover approximately 27 MMBtu/hr of potential waste heat per reactor.
- Steam drum - use of heat exchangers (quench exchangers) to recover heat from the radiant section flue gas and generate medium pressure steam. This heat recovery

creates beneficial steam that is required as dilution steam in the reactors. FPC TX estimates approximately 21.75 MMBtu/hr of additional waste heat is recovered per reactor by selecting this design option.

- Economizer - use of heat exchanger to recover heat from the exhaust gas to preheat incoming steam drum feedwater will maximize thermal efficiency, which reduces the flue gas exhaust temperature to the lowest practical design limit. FPC TX estimates approximately 7 MMBtu/hr of additional waste heat is recovered per reactor by selecting this design option.
- Steam drum blowdown heat recovery: Pressurized hot blowdown from all steam drums having a temperature of approx. 380°F is combined and flashed. The generated steam is used for heating in process condensate stripper. The remaining liquid is used to preheat fresh make-up water in a heat exchanger and then sent to Battery Limits, thus maximizing heat recovery. FPC TX estimates approximately 1.8 MMBtu/hr of additional waste heat is recovered per reactor by selecting this design option.
- Condensate recovery - Process condensate collected in the PDH process after heat recovery contains hydrocarbons which have to be stripped off. This is done in condensate stripper ISBL PDH unit. Heat for the stripper is provided by hot process gas leaving the reactor and by steam generated in the flash of the steam drum blowdown as described above. Instead of sending the stripped condensate to battery limits, it is used as boiler feed water for PDH dilution steam generation directly without cooling therefore no extra preheating is necessary. FPC TX estimates approximately 41.5 MMBtu/hr of additional waste heat is recovered by selecting this design option as compared with a conventional design where the stripped condensate is sent to a demin plant.

By selecting each of these energy efficiency-related design options, FPC TX's reactors are being designed for maximum heat recovery. A numeric energy efficiency-based BACT limit and benchmarking against other sources is addressed in Step 5.

6.6.1.3 Operating and Maintenance Elements Relating to Energy Efficiency

The following operating and maintenance practices were considered and selected to maximize propylene yield by improving reactor efficiency.

- Periodic Tune-up – The reactors are subject to the Boiler MACT (40 CFR 63 Subpart DDDDD) which requires an annual tune-up. These annual tune-ups will promote efficient operation of the reactor and will include the following elements:
    - burner inspection and cleaning or replacement components as necessary,
    - inspection of flame pattern and burner adjustments as necessary to optimize the flame pattern,
    - inspection of the system controlling the air-to-fuel ratio
    - optimize total emissions of carbon monoxide, and
    - measure the concentrations carbon monoxide and oxygen in the exhaust before and after the adjustments are made.
- Burner Routine Inspection and Maintenance - The reactors burners will be visually inspected daily and cleaned at least annually per a preventative maintenance schedule. In order to maintain the combustion efficiency of the burners, maintenance of the burners without necessity of reactor operation interruption is possible due to comparably high number of burners along with easy access on top of the reactor. Routine burner maintenance is expected to minimize dirt deposits that could reduce burner efficiency by as much as 5%.
- Oxygen trim control – Monitoring oxygen concentration in the flue gas and adjustment of inlet air flow will help maximize thermal efficiency. The reactors will be equipped with an oxygen analyzer in the stack. Typically, excess oxygen levels of 3 to 5 percent are optimal for a good combustion profile. The combustion system features air adjustment dampers at the burners which is designed for both automatic and manual (operator) control capability.

    Operation with more than optimum excess air causes energy efficiency losses leading to higher fuel gas consumption due to unnecessary high amount of air to be heated up to combustion temperature. For example, a 3% increase in excess air is expected to result in as much as 1.4% additional fuel usage (approximately 2.7 MMBtu/hr per reactor).

6.6.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.6.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.6.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.6.5 Step 5: Select BACT

FPC TX proposes the selection of all available energy-efficient design options and operational/maintenance practices presented in Step 1 as BACT for the reactors. Since the proposed energy efficiency design options, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, FPC TX is proposing a BACT limit for each reactor which takes into consideration the operation, variability and interaction of all these energy efficient features in combination. A holistic BACT limit which accounts for the ultimate performance of the entire unit was chosen, rather than individual independent subsystem performance. Otherwise, monitoring and maintaining energy efficiency would be un-necessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

FPC TX proposes a numerical energy efficiency-based BACT limit for maximum exhaust gas temperature of 340 ºF averaged on a 365-day rolling average basis. FPC TX will monitor the reactors' flue gas exhaust temperature in accordance with permit conditions.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for gas-fired PDH reactors and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed in other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

Celanese Chemicals – Clear Lake Plant Methanol Unit

Celanese Chemicals submitted a permit application for the construction of a new methanol production unit to EPA Region 6 on August 8, 2012. The application includes a methanol reactor, with a maximum heat input of approximately 860 MMBtu/hr, that combusts methane (natural gas) and hydrogen-rich process gas as fuel gas. It should be noted that this reactor is much larger and has significant differences in design and application (i.e., in methanol production service) than FPC TX's PDH reactors; however, FPC TX is providing a comparison of proposed BACT to accommodate this permit application. Celanese Chemicals proposed firing of natural gas as the primary fuel, selection of new reactor process design, installation of energy efficient options and implementation of select energy efficient operational practices as BACT.

FPC TX is also proposing selection of energy efficient design and operation elements (as described in Step 1) for its new reactors as BACT. In addition, FPC TX is proposing to fire a hydrogen-rich fuel gas as the primary fuel (instead of natural gas) and is also proposing an energy efficiency-based numeric BACT limit (described in Step 5) which establishes an enforceable limit for GHG emissions from the reactors.

6.7 BACT FOR FLARES

6.7.1 Step 1: Identify All Available Control Technologies

Other than CCS, addressed in Section 6.1, the primary GHG control options available are selection of energy efficient and GHG-minimizing design options and implementation of select operation and maintenance procedures to ensure proper operation of the flares on an ongoing basis.

The following discussion lists those design elements and operating and maintenance practices that have been considered and selected to minimize GHG emissions. These individual elements are not being individually considered as BACT control options, rather overall unit design and operation to minimize GHG emissions is considered the BACT option. The individual elements' effects on overall flare efficiency are reflected in the proposed holistic energy efficiency-based BACT limit in Step 5, which limits the quantity of GHG emissions from each flare.

6.7.1.1 Design and Operating Elements that Minimize GHG Emissions

Minimization of Waste Gas to Flare

FPC TX is designing the Olefins 3 plant and PDH unit with fuel gas systems which will provide beneficial reuse of hydrocarbon-containing streams that would otherwise be routed to a flare for control. By incorporating fuel gas system design into the inherent process function, FPC TX's selected design will minimize the amount of process waste gas that could potentially be flared.

Flare Design and Operation

Good flare design ensures that the design hydrocarbon destruction and removal efficiency (DRE) is achieved under real world operating conditions. Specifically, the flare tips are being designed to accommodate maximum design waste gas flow rates and achieve optimal combustion profile at the flare tip (e.g., optimal air and waste gas mixing) to ensure at least 98% destruction (weight percent) of VOCs and 99% destruction of methane.

Each flares' pilot flames are being designed to use natural as the primary fuel. By selecting natural gas as the fuel gas for the flare pilots, FPC TX is selecting the lowest carbon-intensity fuel available and thus minimizing GHG emissions from the flare pilots.

As addressed in the TCEQ permit application, the flares are being designed in accordance with the design requirements of 40 CFR 60.18. Specifically, natural gas will be added to the flare headers such that the minimum waste gas heating value is maintained. The flares are also being designed so the maximum tip allowable velocity is not exceeded under normal operating conditions. Finally, the flares will be equipped with a monitoring system to ensure that there is a pilot at all times that waste gas may be directed to the flares and they will also be equipped with waste gas flow rate monitors.

6.7.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.7.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.7.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.7.5 Step 5: Select BACT

FPC TX proposes the selection of all available design and operational elements that minimize GHG emissions presented in Step 1 as BACT for the elevated and low pressure flares. Since the proposed design and operating elements, described in Step 1 above, are not independent features but are interdependent and represent an integrated energy efficiency strategy, FPC TX is proposing a BACT limit for each flare which takes into consideration the operation, variability and interaction of all these features in combination. A holistic BACT limit which accounts for the ultimate performance of the entire unit was chosen, rather than individual independent subsystem performance. Otherwise, monitoring and maintaining energy efficiency would be unnecessarily complex because the interdependent nature of operating parameters means that one parameter cannot necessarily be controlled independently without affecting the other operating parameters.

FPC TX proposes that the annual GHG emission limit (tpy CO_2e) for each flare, as presented in Appendix A, serve as the numerical BACT limit on a rolling 12-month basis.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for flaring and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

Equistar La Porte – Olefins Expansion

The Equistar permit application proposes good flare design and operation (meeting 40 CFR 60.18), natural gas pilots and appropriate instrumentation as BACT. FPC TX is proposing BACT that is similar to, or the same as the one proposed by Equistar for its flares. As described in Step 5, FPC TX is also proposing to use hydrogen-rich fuel gas as the primary fuel for the flare pilots and is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from the flares.

Chevron Phillips Chemical Company LP – Cedar Bayou Plant, New Ethylene Unit

The Chevron Phillips application proposes low carbon fuel gas (natural gas) for the flare pilot and supplemental gas and good combustion practices (in accordance with flare manufacturer) as BACT. FPC TX is proposing BACT that is similar to, or the same as the one proposed by Chevron Phillips. As described in Step 5, FPC TX is also proposing to use hydrogen-rich fuel gas as the primary fuel for the flare pilots and is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from the flares.

ExxonMobil Baytown Olefins Plant

The ExxonMobil permit application proposes proper flare design and operation to maintain required waste gas heating value and tip velocity and selection of staged flaring with natural gas assist as BACT. FPC TX is proposing BACT that is similar to the one proposed by ExxonMobil; however, FPC TX is not proposing a staged flaring scheme with its expansion project as the elevated flare will serve both the Olefins 3 and LDPE plants. FPC TX is, instead, proposing to select design and operating elements described in Step 1 that minimize GHG emissions and is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from the flares.

ExxonMobil Mont Belvieu Plastics Plant

On May 21, 2012 ExxonMobil Chemical Company submitted a permit application to EPA Region 6 for the construction of a new polyethylene unit. The ExxonMobil permit application requests authorization of a new low profile flare and proposes proper flare operation and natural gas assist as BACT. FPC TX is proposing BACT that is similar to the one proposed by ExxonMobil. As described in Step 1, FPC TX is also proposing to use hydrogen-rich fuel gas as the primary fuel for the flare pilots and is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from the flares.

Celanese Chemicals Clear Lake Plant Methanol Unit

The Celanese permit application proposed construction of a new flare for MSS activity and emergency use. Celanese Chemicals proposes good flare design with appropriate instrumentation and control as BACT for the flare. FPC TX is proposing BACT that is similar to the one proposed by Celanese Chemicals. As described in Step 1, FPC TX is also proposing to use hydrogen-rich fuel gas as the primary fuel for the flare pilots and is also proposing a numeric BACT limit which establishes an enforceable limit for GHG emissions from the flares.

6.8 BACT FOR NATURAL GAS AND FUEL GAS PIPING FUGITIVES

6.8.1 Step 1: Identify All Available Control Technologies

The following available control technologies for fugitive piping components emitting GHGs (those in natural gas and fuel gas service) were identified:

- Installation of leakless technology components to eliminate fugitive emission sources.
- Implementing leak detection and repair (LDAR) programs (those used for VOC components) in accordance with applicable state and federal air regulations.
- Implement alternative monitoring using a remote sensing technology such as infrared camera monitoring.
- Implementing an audio/visual/olfactory (AVO) monitoring program typically used for non-VOC compounds.

6.8.2 Step 2: Eliminate Technically Infeasible Options

All the available options are considered technically feasible and have been used in industry as described below.

Leakless valves are primarily used where highly toxic or otherwise hazardous materials are present. Leakless valves are expensive in comparison to a standard (non-leakless) valve. These technologies are generally considered cost prohibitive except for specialized service.

LDAR programs are typically implemented for control of VOC emissions from materials in VOC service (at least 5 wt% VOC or HAP), however instrument monitoring may also be technically feasible for components in CH4 service, including the fuel gas and natural gas piping fugitives.

Remote sensing technologies have been proven effective in leak detection and repair, especially on larger pipeline-sized lines. The use of sensitive infrared camera technology has become widely accepted as a cost-effective means for identifying leaks of hydrocarbons depending on the number of sources.

AVO monitoring methods are also capable of detecting leaks from piping components as leaks can be detected by sound (audio) and sight. AVO programs are commonly used in industry and technically feasible for the GHG fugitives in the Olefins 3 plant.

6.8.3 Step 3: Rank Remaining Control Technologies

AVO monitoring has been implemented historically at the Point Comfort plant. AVO monitoring is as effective in detecting significant leaks as Method 21 instrument or remote sensing monitoring if AVO inspections are performed frequently enough. AVO detections can be performed very frequently, at lower cost and with less additional manpower and equipment than Method 21 instrument or remote sensing monitoring because it does not require a specialized piece of monitoring equipment. Therefore, for components in methane (natural gas or fuel gas) service AVO is considered the most preferred technically feasible alternative.

Remote sensing using infrared imaging has been accepted by EPA as an acceptable alternative to Method 21 instrument monitoring and leak detection effectiveness is expected to be comparable. Although less manpower may be required for remote sensing compared to Method 21 depending on the number of sources, the frequency of monitoring is more limited than AVO because the number of simultaneous measurements will be limited by the availability of the remote sensing equipment.

Method 21 Instrument monitoring has historically been used to identify leaks in need of repair. However, instrument monitoring requires significant allocation of manpower as compared to AVO monitoring, while AVO is expected to be equally effective at identifying significant leaks.

Leakless technologies are effective in eliminating fugitive emissions from the locations where installed. However, because of their high cost, these specialty components are, in practice, selectively applied only as absolutely necessary to toxic or hazardous components.

6.8.4 Step 4: Evaluate Most Effective Controls and Document Results

The AVO monitoring option is expected to be effective in finding leaks, can be implemented at the greatest frequency and lower cost due to being incorporated into routine operations.

The use of Method 21 instrument leak detection is technically feasible, however the leak effectiveness, in comparison to AVO monitoring, is likely similar or less for components in methane service. However, Method 21 instrument monitoring is much more costly and requires much more manpower than AVO monitoring. In addition AVO monitoring can be done at a much greater frequency thus allowing detection of leaks more quickly.

Remote sensing monitoring has lower cost than Method 21 instrument monitoring but still much more costly than AVO. Typically, remote sensing is more applicable to larger potential emission sources that contain critical fugitive components with the potential for high volume leaks. In addition, remote sensing can be performed on a limited frequency because it requires specialized equipment. Remote sensing is not practicable for small fugitive sources

Leakless technologies have not been universally adopted as BACT for emission from fugitive piping components, even for hazardous services. Therefore, FPC TX believes that these technologies are not practical for control of GHG emissions from methane piping components.

6.8.5 Step 5: Select BACT

Please note the total GHG fugitive emissions are expected to be less than 0.005% of the total GHG emissions from the proposed Olefins 3 plant. FPC- TX proposes to perform weekly AVO monitoring of piping components associated with the Olefins 3 plant that are in GHG service (natural gas and fuel gas service).

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for piping fugitive GHG emissions and found no entries which address BACT for GHG emissions. Although not listed in the RACT/BACT/LAER Clearinghouse, a GHG BACT analysis was performed by other GHG permit applications submitted to EPA Region 6. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

- **Equistar Channelview – Olefins I&II Expansions**
    - The Equistar applications request authorization of GHG emissions from piping components. These applications propose remote sensing of "pipeline sized" components that are not otherwise subject to Method 21 monitoring.

- **Equistar La Porte – Olefins Expansion**
    - The Equistar permit application proposes to employ TCEQ's 28 LAER fugitive leak detection and repair program for components "in CH4 service" as BACT, however "in CH4 service" is not defined in the application.
- **Chevron Phillips Chemical Company LP – Cedar Bayou Plant, New Ethylene Unit**
    - The Chevron Phillips application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas and fuel gas piping components as BACT.
- **ExxonMobil Baytown Olefins Plant**

    - The ExxonMobil application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas piping components and applicable TCEQ LDAR programs for components in VOC service as BACT.
- **ExxonMobil Mont Belvieu Plastics Plant**
    - ExxonMobil application proposes as-observed AVO (audio/visual/olfactory) monitoring for natural gas piping components and applicable TCEQ LDAR programs for components in VOC service as BACT.
- **INEOS USA LLC – Olefins Expansion**
    - The INEOS permit requires TCEQ’s 28VHP LDAR program for fugitive piping components in methane service.
- **BASF FINA - NAFTA Region Olefins Complex**
    - The permit stipulates the use of TCEQ’s 28LAER LDAR program for all fugitive emissions of methane.

FPC TX’s proposed weekly AVO monitoring is equally as effective and can be performed at greater frequency as instrument monitoring. Therefore, FPC TX’s proposed BACT for fugitive components is as effective as BACT proposed in other applications.

7.0 OTHER PSD REQUIREMENTS

7.1 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 or 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.*[16]

An impacts analysis for non-GHG emissions is being submitted with the State/PSD/Non-attainment application submitted to the TCEQ.

7.2 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.*[17]

A pre-construction monitoring analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

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[16] EPA, *PSD and Title V Permitting Guidance For Greenhouse Gases* at 48-49.
[17] *Id.* at 49.

7.3 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 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.*[18]

A PSD additional impacts analysis for non-GHG emissions is being submitted with the State/PSD/Nonattainment application submitted to the TCEQ.

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[18] *Id.*

APPENDIX A

GHG EMISSION CALCULATIONS

Table A-1
Plantwide GHG Emission Summary
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Name	EPN	GHG Mass Emissions [1]	CO_2e [1]
		ton/yr	ton/yr
Cracking Furnace 1	OL3-FUR1	125,279	125,410
Cracking Furnace 2	OL3-FUR2	125,279	125,410
Cracking Furnace 3	OL3-FUR3	125,279	125,410
Cracking Furnace 4	OL3-FUR4	125,279	125,410
Cracking Furnace 5	OL3-FUR5	125,279	125,410
Cracking Furnace 6	OL3-FUR6	125,279	125,410
Cracking Furnace 7	OL3-FUR7	125,279	125,410
Cracking Furnace 8	OL3-FUR8	125,279	125,410
Cracking Furnace 9	OL3-FUR9	125,279	125,410
Cracking Furnace 10	OL3-FUR10	125,279	125,410
Cracking Furnace 11	OL3-FUR11	125,279	125,410
Cracking Furnace 12	OL3-FUR12	125,279	125,410
Cracking Furnace 13	OL3-FUR13	125,279	125,410
Cracking Furnace 14	OL3-FUR14	125,279	125,410
Steam Boiler 1	OL3-BOIL1	210,690	210,912
Steam Boiler 2	OL3-BOIL2	210,690	210,912
Steam Boiler 3	OL3-BOIL3	210,690	210,912
Steam Boiler 4	OL3-BOIL4	210,690	210,912
PDH Reactor 1	PDH-REAC1	59,622	59,726
PDH Reactor 2	PDH-REAC2	59,622	59,726
PDH Reactor 3	PDH-REAC3	59,622	59,726
PDH Reactor 4	PDH-REAC4	59,622	59,726
Olefins 3 Fugitives	OL3-FUG	4.83	96.5
PDH Fugitives	PDH-FUG	1.17	19.50
Elevated Flare [2]	OL3-FLRA, OL3-FLRB	76,305	83,970
Low Pressure Flare 1 [2]	OL3-LPFLR1	1,103	1,158
Low Pressure Flare 2 [2]	OL3-LPFLR2	1,103	1,158
Decoking Drum 1 [3]	OL3-DK1	329	329
Decoking Drum 2 [3]	OL3-DK2		
MAPD Regenerator Vent	OL3-MAPD	32.8	32.8
PDH Unit MSS Vessel Opening	PDH-MSSVO	3.12	8.20
Olefins 3 Plant MSS Vessel Opening	OL3-MSSVO	2.22	46.0
Olefins 3 Emergency Engine	OL3-GEN	447	449
PDH Emergency Engine	PDH-GEN	447	449
	total =	***2,914,925***	***2,926,008***

Note:

[1] Combustion unit emissions (furnace, boiler, reactors) include emissions from both fuel gas and natural gas combustion. CO2e emissions in units of short (English) tons per year.

[2] Flare emissions include emissions from flare pilot and waste gas combustion.

MSS emissions associated with flares streams are also included in the elevated flare value.

[3] Emissions from furnace decoking may occur from either decoking drum 1 or 2.

Table A-2
GHG Emission Calculations - Natural Gas Combustion
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

GHG Emissions Contribution From Natural Gas Fired Combustion:

						Emissions per Unit			
Source Type	**Average Heat Input/Unit (MMBtu/hr)**	**Annual Operation per Unit (hrs/yr)**	**Annual Avg Heat Input, Each Unit (MMBtu/yr)**	**Pollutant**	**Emission Factor (kg/MMBtu)[1]**	**GHG Mass Emissions[2] (metric ton/yr)**	**Global Warming Potential[3]**	**CO_2e (metric ton/yr)**	**CO_2e (tpy)**
Pyrolysis Furnaces	220	700	154,000	CO_2	53.02	8,165	1	8,165	9,002
				CH_4	1.0E-03	0.15	21	3.23	3.57
				N_2O	1.0E-04	0.02	310	4.77	5.26
					Totals	**8,165**		**8,173**	**9,011**
PDH Unit Reactors	191	970	185,000	CO_2	53.02	9,809	1	9,809	10,814
				CH_4	1.0E-03	0.19	21	3.89	4.28
				N_2O	1.0E-04	0.02	310	5.74	6.32
					Totals	**9,809**		**9,818**	**10,825**
Steam Boilers	431	405	175,000	CO_2	53.02	9,279	1	9,279	10,230
				CH_4	1.0E-03	0.18	21	3.68	4.05
				N_2O	1.0E-04	0.02	310	5.43	5.98
					Totals	**9,279**		**9,288**	**10,240**
Elevated Flare Pilots	0.50	8,760	4,000	CO_2	53.02	212	1	212	234
				CH_4	1.0E-03	4.00E-03	21	0.08	0.09
				N_2O	1.0E-04	4.00E-04	310	0.12	0.14
					Totals	**212.1**		**212**	**234**
Low Pressure Flare Pilots (each)	0.40	8,760	4,000	CO_2	53.02	212	1	212	234
				CH_4	1.0E-03	4.00E-03	21	0.08	0.09
				N_2O	1.0E-04	4.00E-04	310	0.12	0.14
					Totals	**212.1**		**212**	**234**
Total, All Natural Gas Combustion						***27,677***		***27,704***	***30,543***

Notes:

1. CO2 GHG factor from Table C-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting (GHG MRR).

CH4 and N2O GHG factors based on Table C-2 of GHG MRR.

2. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-1.

CH_4 and N_2O emissions based on 40 CFR Part 98, Subpart C, Equation C-8.

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

Sample Calculation: Pyrolysis Furnaces - CO_2:

GHG Mass Emissions (metric ton/yr) = 0.001 x 154000 (MMBtu/yr) x 53.02 kg/MMBtu = 8165

CO2e (metric ton/yr) = 8165 (metric ton/yr) x 1 = 8165.1

Table A-3
GHG Emission Calculations - Fuel Gas Combustion
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Fuel Gas Data:

Variable	Value		Units	Reference
	Olefins 3 Fuel Gas	PDH Unit Fuel Gas		
HHV	522	387	Btu/scf	design specification
Carbon Content (Annual Avg)	0.700	0.363	kg C/kg	design specification
Molecular Weight (Annual Avg)	8.32	6.49	kg/kg-mol	design specification

GHG Emissions Contribution From Fuel Gas Fired Combustion:

										Emissions per Unit			
Source Type	**Fuel Gas Type**	**Average Heat Input/Unit (MMBtu/hr)**	**Annual Average Fuel Gas Usage/Unit[1] (MMscf/hr)**	**Number of Units**	**Annual Operation (hrs/yr)**	**Annual Average Fuel Use, Each Unit (scf/yr)**	**Annual Average Heat Input, Each Unit (MMBtu/yr)**	**Pollutant**	**Emission Factor (kg/MMBtu)[2]**	**GHG Mass Emissions[3] (metric ton/yr)**	**Global Warming Potential[4]**	**CO_2e (metric ton/yr)**	**CO_2e (tpy)**
Pyrolysis Furnace	Olefins 3	250	0.479	14	8,760	4.20E+09	2.19E+06	CO_2		105,464	1	105,464	116,274
								CH_4	1.0E-03	2.19	21	45.99	50.70
								N_2O	1.0E-04	0.22	310	67.89	74.85
									Totals	**105,466**		**105,578**	**116,399**
Steam Boilers	Olefins 3	431	0.826	4	8,760	7.23E+09	3.78E+06	CO_2		181,819	1	181,819	200,456
								CH_4	1.0E-03	3.78	21	79.29	87.41
								N_2O	1.0E-04	0.38	310	117.04	129.04
									Totals	**181,824**		**182,016**	**200,672**
PDH Unit reactors	PDH	191	0.494	4	8,760	4.32E+09	1.67E+06	CO_2		43,963	1	43,963	48,469
								CH_4	1.0E-03	1.67	21	35	39
								N_2O	1.0E-04	0.17	310	52	57
									Totals	**43,965**		**44,050**	**48,565**
Total, All Fuel Gas Combustion										***331,254***		***331,643***	***365,637***

Notes:

1. Fuel use calculated as: MMscf/hr = Firing rate (MMBtu/hr) / HHV (Btu/scf)

2. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

CH_4 and N_2O emissions based on 40 CFR Part 98, Subpart C, Equation C-8.

3. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-5.

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

Sample Calculation: Pyrolysis Furnaces - CO_2:

GHG Mass Emissions (metric ton/yr) = (44/12) x 4.20E+09 (scf/yr) x 0.7 kg C/kg x 8.32 kg/kg-mol / 849.5 scf/kg-mole @ std cond. x 0.001 = 1.05E+05

CO2e (metric ton/yr) = 1.05E+05 (metric ton/yr) x 1 = 1.05E+05

Table A-4
GHG Emission Calculations - PDH Regeneration Gas Combustion
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

PDH Regeneration Gas Data:

Variable	Value	Units	Reference
Carbon Content (Annual Avg)	0.0044	kg C/kg	design specification
Heating Value	0.2005	Btu/scf	design specification
Molecular Weight (Annual Avg)	28.21	kg/kg-mol	design specification

GHG Emissions Contribution From Regeneration Gas Combustion in PDH Reactors:

							Emissions per Unit			
Source Type	Annual Average Fuel Gas Usage/Unit (scf/hr)	Number of Units	Annual Operation (hrs/yr)	Annual Average Fuel Use, Each Unit (scf/yr)	Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions[2] (metric ton/yr)	Global Warming Potential[3]	CO_2e (metric ton/yr)	CO_2e (tpy)
PDH Unit reactors	64,983	4	8,760	5.69E+08	CO_2		305	1	305	336
					CH_4	1.0E-03	1.14E-04	21	0	2.64E-03
					N_2O	1.0E-04	1.14E-05	310	0	3.90E-03
						TOTAL =	***305***		***305***	***336***

Notes:

1. CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.
CH_4 and N_2O emissions based on 40 CFR Part 98, Subpart C, Equation C-8.
*CH_4 / N_2O = 1E-03 * Fuel * HHV * EF*

2. CO_2 emissions based on 40 CFR Part 98, Subpart C, Equation C-5.
*CO_2 = 44/12 * Fuel * CC* MW / MVC *0.001*

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

Sample Calculation, CO_2:

GHG Mass Emissions (metric ton/yr) = (44/12) x 5.69E+08 (scf/yr) x 0.0044 kg C/kg x 28.21 kg/kg-mol / 849.5 scf/kg-mole @ std cond. x 0.001 = 3.05E+02
CO2e (metric ton/yr) = 3.05E+02 (metric ton/yr) x 1 = 3.05E+02

Table A-5
GHG Emission Calculations - Flares
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Flare Gas Data:

Variable	Values			Units	Reference
	Elevated Flare 1st Stage	Elevated Flare 2nd Stage	Low Pressure Flares		
Carbon Content (Annual Avg)	0.81	0.73	0.03	kg C/kg	design specification
Molecular Weight (Annual Avg)	26.2	16.7	15.0	kg/kgmol	design specification

GHG Emissions from Flares:

Source Type	Annual Avg Flare Gas Flow Rate (scf/yr)	Pollutant	GHG Mass Emissions[2] (metric ton/yr)	Global Warming Potential[3]	CO_2e (metric ton/yr)	CO_2e (tpy)
Elevated Flare 1st Stage	1.84E+08	CO_2	16,581	1	16,581	18,281
		CH_4	50.05	21	1,051	1,159
		N_2O	0.17	310	51.40	56.67
			16,631		**17,684**	**19,496**
Elevated Flare 2ndStage	1.05E+07	CO_2	545	1	545	601
		CH_4	1.64	21	34.5	38.1
		N_2O	0.01	310	1.69	1.86
			547		**581**	**641**
Low Pressure Flare 1	3.68E+08	CO_2	786	1	786	866
		CH_4	2.37	21	50	55
		N_2O	7.86E-03	310	2.44	2.68
			788		**838**	**924**
Low Pressure Flare 2	3.68E+08	CO_2	786	1	786	866
		CH_4	2.37	21	50	55
		N_2O	7.86E-03	310	2.44	2.68
			788		**838**	**924**
Total, All Flare Gas Combustion		**Totals**	***18,754***		***19,940***	***21,984***

Notes:

1. *CH_4 and N_2O GHG factors based on Table C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
2. *CO_2 emissions based on 40 CFR Part 98, Subpart Y, Equation Y-1a.*
3. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Sample Calculation: Elevated Flare - CO_2:

GHG Mass Emissions (metric ton/yr) = (44/12) x 1.84E+08 (scf/yr) x 0.813 kg C/kg x 26.21 kg/kgmol / 849.5 scf/kg-mole @ std cond. x 0.001 x 0.98 = 1.66
CO2e (metric ton/yr) = 1.66E+04 (metric ton/yr) x 1 = 1.66E+04

Table A-6
GHG Emission Calculations - Decoking
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Decoking Information:

Variable	Value	Units	Reference
Volumetric Flow Rate During Decoking	714,636	scf/hr	design specification
CO_2 Concentration	0.10	mol %	design specification
CH_4 Concentration	0	mol %	design specification
Decoking Duration (Per Event)	48	hours	design specification
Number of Furnaces	14	qty	Formosa design data
Decoking Frequency (Per Furnace)	12	events/yr/ furnace	design specification

Constants:

Field	Value	Units
CO_2 Molecular Weight	44	kg/kgmol
CH_4 Molecular Weight	16	kg/kg-mol
Molar Volume Conversion	849.50	scf/kg-mol
Conversion Factor	0.001	metric ton/kg

CO_2 Emissions from Furnace Decoking:

Source Type	Pollutant	GHG Mass Emissions[1] (metric ton/yr)	Global Warming Potential[2]	CO_2e (metric ton/yr)	CO_2e (tpy)
Furnace Decoke [3]	CO_2	298	1	**298**	**329**
	CH_4	0.00	21	**0.00**	**0.00**
Total, Decoking		***298***		***298***	***329***

Notes:

1. *CO_2 and CH_4 emissions based on 40 CFR Part 98, Subpart Y, Equation Y-19.*
2. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*
3. *Emissions from decoking may occur from either decoking drum 1 or 2.*

Sample Calculation: Furnace Decoking - CO_2:

GHG Mass Emissions (metric ton/yr) = 714636 scf/hr x 12 events/yr/ furnace x 14 qty x 48 hours x (0.1/100) x 44 kg/kgmol/ 849.5 scf/kg-mol x 0.001 metric ton/kg = 298.5

CO2e (metric ton/yr) = 298 (metric ton/yr) x 1 = 298

Table A-7
GHG Emission Calculations - MAPD Regen Vent
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

MAPD Regen Vent Data:

Variable	Value	Units	Reference
Volumetric Flow Rate (Annual Avg)	191,559	scf/hr	design specification
CO_2 Concentration	3.0	mol %	design specification
CH_4 Concentration	0	mol %	design specification
Maximum Vent Operating Schedule	100	hours/yr	design specification

Constants:

Field	Value	Units
CO_2 Molecular Weight	44	kg/kgmol
CH_4 Molecular Weight	16	kg/kg-mol
Molar Volume Conversion	849.50	scf/kg-mol
Conversion Factor	0.001	metric ton/kg

CO_2 Emissions from MAPD Regen Vent:

Source Type	Pollutant	GHG Mass Emissions[1] (metric ton/yr)	Global Warming Potential[2]	CO_2e (metric ton/yr)	CO_2e (tpy)
MAPD Regen Vent	CO_2	29.8	1	29.8	32.8
	CH_4	0.00	21	0.00	0.00
Total, Regen Vent		***29.8***		***29.8***	***32.8***

Notes:

1. CO_2 and CH_4 emissions based on 40 CFR Part 98, Subpart Y, Equation Y-19.

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

Sample Calculation: MAPD Regen Vent - CO_2:

GHG Mass Emissions (metric tpy) = 191559 scf/hr x (3/100) x 100 hours/yr x
44 kg/kgmol / 849.5 scf/kg-mol x 0.001 metric ton/kg = 29.8
CO2e (metric ton/yr) = 30 (metric ton/yr) x 1 = 30

Table A-8
GHG Emission Calculations - Emergency Engines
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Diesel Emergency Engine Specifications:

Variable	Value	Units	Reference
Annual Operating Schedule	100	hours/year	RICE MACT limitation
Power Rating	676	hp	design specification
Brake Specific Fuel Consumption	8,110	Btu/hp-hr	design specification

GHG Emissions Contribution From Diesel Combustion:

Source	Heat Input (MMBtu/hr)	Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions (metric ton/yr)	Global Warming Potential[2]	CO_2e (metric ton/yr)	CO_2e (tpy)
Olefins 3 Emergency Engine	54.8	CO_2	73.96	405	1	405	447
		CH_4	3.0E-03	1.64E-02	21	0.35	0.38
		N_2O	6.0E-04	3.29E-03	310	1.02	1.12
PDH Emergency Engine	54.8	CO_2	73.96	405	1	405	447
		CH_4	3.0E-03	0.02	21	0.35	0.38
		N_2O	6.0E-04	0.00	310	1.02	1.12
Total, Emergency Engines			**Totals**	***811***		***814***	***897***

Notes:

1. GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.

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

3. Annual Emission Rate = Heat Input x Emission Factor x 0.001 metric ton/kg x hours/year x Global Warming Potential

Sample Calculation: Diesel Combustion - CO_2*:*

GHG Mass Emissions (metric ton/yr) = 54.8 (MMBtu/hr) x 73.96 kg/MMBtu x 2.2 x 100 hours/year / 2000 = 405
CO2e (metric ton/yr) = 405 (metric ton/yr) x 1 = 405

Table A-9
GHG Emission Calculations - Piping Fugitives
Formosa Plastic Corporation, Texas
Olefins Expansion
April 2013

Olefins 3 Unit Fuel Gas and N.G. Piping Components:

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2 Content (vol %)	CH_4 Content (vol %)	CO_2 (tpy)	CH_4 (tpy)	Total (tpy)
OL3-FUG	Valves	Gas/Vapor	308	0.121	1.00%	50.0%	1.86E-01	3.396	
	Flanges	Gas/Vapor	765	0.017			6.50E-02	1.185	
	Compressors	Gas/Vapor	3	0.007			1.05E-04	1.91E-03	
GHG Mass-Based Emissions							0.25	4.58	***4.83***
Global Warming Potential[3]							1	21	
CO_2e Emissions							0.25	96.24	***96.49***

PDH Unit Fuel Gas and N.G. Piping Components:

EPN	Source Type	Fluid State	Count	Emission Factor[1] scf/hr/comp	CO_2 Content (vol %)	CH_4 Content (vol %)	CO_2 (tpy)	CH_4 (tpy)	Total (tpy)
PDH-FUG	Valves	Gas/Vapor	308	0.121	1.00%	10.0%	1.86E-01	0.679	
	Flanges	Gas/Vapor	765	0.017			6.50E-02	0.237	
	Compressors	Gas/Vapor	3	0.007			1.05E-04	3.83E-04	
GHG Mass-Based Emissions							0.25	0.92	***1.17***
Global Warming Potential[3]							1	21	
CO_2e Emissions							0.25	19.25	***19.50***

Notes:

1. *Emission factors from Table W-1A of 40 CFR 98 Mandatory Greenhouse Gas Reporting published in the May 21, 2012 Technical Corrections*
2. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Sample Calculation: OL3 Valve GHG Emissions - CO_2:

308 valves	*0.121 scf gas*	*0.01 scf CO2*	*lbmol*	*44.01 lb CO_2*	*8760 hr*	*ton =*	*0.1864*	*ton/yr*
	*hr * valve*	*scf gas*	*385.5 scf*	*lbmol*	*yr*	*2000 lb*		

Table A-10

GHG MSS Emission Calculations - Olefins 3 Plant
Formosa Plastics Corporation, Texas
Olefins Expansion

May 2013

MSS Activity	MSS Activity Category	GHG Mass Emissions (metric ton/yr)	CO$_2$e (metric ton/yr)	CO$_2$e (tpy)
Equipment Opening to Atmosphere EPN: OL3-MSSVO	Startup/shutdown	0.00	0.00	0.00
	Turnaround	0.17	3.48	3.84
	Piping	0.79	16.23	17.90
	Pressure Tanks	0.00	0.00	0.00
	Tanks	0.00	0.00	0.00
	Large Equipment	0.33	6.72	7.41
	Small Equipment Components	0.33	6.73	7.42
	Misc.	0.41	8.54	9.41
	Subtotal	**2.02**	**41.7**	**46.0**
Flare Emissions EPNs: OL3-FLRA, OL3-FLRB	Startup/shutdown	21,164	21,515	23,717
	Turnaround	4,903	4,989	5,499
	Piping	57	60	66
	Pressure Tanks	1,130	1,135	1,251
	Tanks	7	7	8
	Large Equipment	296	299	329
	Small Equipment Components	1,671	1,705	1,879
	Misc.	244	252	277
	Subtotal	**29,472**	**29,962**	**33,027**
Total		**29,474**	**30,003**	**33,073**

Table A-11

GHG MSS Emission Calculations - PDH Unit
Formosa Plastics Corporation, Texas
Olefins Expansion

May 2013

MSS Activity	MSS Activity Category	GHG Mass Emissions (metric ton/yr)	CO_2e (metric ton/yr)	CO_2e (tpy)
Equipment Opening to Atmosphere EPN: PDH-MSSVO	Startup/shutdown	0.516	3.977	4.383
	Turnaround	0.000	0.000	0.000
	Piping	0.0005	0.002	0.003
	Tanks	0.00	0.00	0.00
	Pressure Tanks	0.00	0.00	0.00
	Large Equipment	0.97	0.99	1.09
	Small Equipment Components	0.92	1.66	1.83
	Misc.	0.43	0.81	0.89
	Subtotal	**2.83**	**7.44**	**8.20**
Flare Emissions EPNs: OL3-FLRA, OL3-FLRB	Startup/shutdown	18,054	22,856	25,194
	Turnaround	2,353	2,789	3,074
	Piping	23	27	30
	Tanks	0.6	0.6	0.7
	Pressure Tanks	350	352	388
	Large Equipment	1,294	1,370	1,510
	Small Equipment Components	185	230	253
	Misc.	89	112	123
	Subtotal	**22,348**	**27,735**	**30,573**
	Total	**22,351**	**27,743**	**30,581**

APPENDIX B

PSD NETTING TABLES

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.:	TBD	Application Submittal Date:	
Company	Formosa Plastic Corporation, Texas		
RN:	RN100218973	Facility Location:	201 Formosa Drive
City	Point Comfort	County:	Calhoun
Permit Unit I.D.:	2012 Expansion Project	Permit Name:	TBD
Permit Activity:	☐ New Major Source	☑ Modification	
Project or Process Description:	Olefins Expansion, LDPE Plant and Gas Turbines		

Complete for all pollutants with a project emission increase.	POLLUTANTS						
	Ozone		CO	SO_2	PM	GHG	CO_2e
	NOx	VOC					
Nonattainment? (yes or no)						No	No
Existing site PTE (tpy)	This form for GHG only					>100,000	>100,000
Proposed project increases (tpy from 2F)						4,027,334	4,067,332
Is the existing site a major source? If not, is the project a major source by itself? (yes or no)	Yes						
If site is major, is project increase significant? (yes or no)						Yes	Yes
If netting required, estimated start of construction:		9/1/13					
5 years prior to start of construction:		9/1/08	Contemporaneous				
estimated start of operation:		10/1/15	Period				
Net contemporaneous change, including proposed project, from Table 3F (tpy)						4,027,334	4,067,332
FNSR applicable? (yes or no)						Yes	Yes

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

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

Signature Title Date

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	GHG Mass Emissions	**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A

					A	B				
Affected or Modified Facilities[2]			**Permit No.**	**Actual Emissions[3]**	**Baseline Emissions[4]**	**Proposed Emissions[5]**	**Projected Actual Emissions**	**Difference (B - A)[6]**	**Correction[7]**	**Project Increase[8]**
	FIN	**EPN**								
Olefins 3 Plant Sources										
1	OL3-FUR1	OL3-FUR1		0.00	0.00	125,279		125,279		125,279
2	OL3-FUR2	OL3-FUR2		0.00	0.00	125,279		125,279		125,279
3	OL3-FUR3	OL3-FUR3		0.00	0.00	125,279		125,279		125,279
4	OL3-FUR4	OL3-FUR4		0.00	0.00	125,279		125,279		125,279
5	OL3-FUR5	OL3-FUR5		0.00	0.00	125,279		125,279		125,279
6	OL3-FUR6	OL3-FUR6		0.00	0.00	125,279		125,279		125,279
7	OL3-FUR7	OL3-FUR7		0.00	0.00	125,279		125,279		125,279
8	OL3-FUR8	OL3-FUR8		0.00	0.00	125,279		125,279		125,279
9	OL3-FUR9	OL3-FUR9		0.00	0.00	125,279		125,279		125,279
10	OL3-FUR10	OL3-FUR10		0.00	0.00	125,279		125,279		125,279
11	OL3-FUR11	OL3-FUR11		0.00	0.00	125,279		125,279		125,279
12	OL3-FUR12	OL3-FUR12		0.00	0.00	125,279		125,279		125,279
13	OL3-FUR13	OL3-FUR13		0.00	0.00	125,279		125,279		125,279
14	OL3-FUR14	OL3-FUR14		0.00	0.00	125,279		125,279		125,279
15	OL3-BOIL1	OL3-BOIL1		0.00	0.00	210,690		210,690		210,690
16	OL3-BOIL2	OL3-BOIL2		0.00	0.00	210,690		210,690		210,690
17	OL3-BOIL3	OL3-BOIL3		0.00	0.00	210,690		210,690		210,690
18	OL3-BOIL4	OL3-BOIL4		0.00	0.00	210,690		210,690		210,690
19	PDH-REAC1	PDH-REAC1		0.00	0.00	59,622		59,622		59,622
20	PDH-REAC2	PDH-REAC2		0.00	0.00	59,622		59,622		59,622
21	PDH-REAC3	PDH-REAC3		0.00	0.00	59,622		59,622		59,622
22	PDH-REAC4	PDH-REAC4		0.00	0.00	59,622		59,622		59,622
23	OL3-FUG	OL3-FUG		0.00	0.00	4.83		4.83		4.83

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant(1):	GHG Mass Emissions	**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A

Affected or Modified Facilities(2)			Permit No.	Actual Emissions(3)	A Baseline Emissions(4)	B Proposed Emissions(5)	Projected Actual Emissions	Difference (B - A)(6)	Correction(7)	Project Increase(8)
	FIN	EPN								
24	PDH-FUG	PDH-FUG		0.00	0.00	1.17		1.17		1.17
25	OL3-FLRA, OL3-FLRB	OL3-FLRA, OL3-FLRB		0.00	0.00	76,305	see Note 1	76,305		76,305
26	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	1,102.5		1,102.5		1,102.5
27	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	1,102.5		1,102.5		1,102.5
28	OL3-DK1	OL3-DK1		0.00	0.00	329.1		329.1		329.1
29	OL3-DK2	OL3-DK2		0.00	0.00					
30	OL3-MAPD	OL3-MAPD		0.00	0.00	32.8		32.8		32.8
31	PDH-MSSVO	PDH-MSSVO		0.00	0.00	3.12		3.12		3.12
32	OL3-MSSVO	OL3-MSSVO		0.00	0.00	2.22		2.22		2.22
33	OL3-GEN	OL3-GEN		0.00	0.00	447		447		447
34	PDH-GEN	PDH-GEN		0.00	0.00	447		447		447
35	N6460FA/B	1087	19168	2.33	2.33	2.82	see Note 2	0.49		0.49
LDPE Plant Sources										
36	LD-022A/B	LD-022A/B		0.00	0.00	31,550		31,550		31,550
37	LD-023A/B	LD-023A/B		0.00	0.00					
38	OL3-FLR	OL3-FLR		0.00	0.00	21,933	see Note 1	21,933		21,933
39	LD-014	LD-014		0.00	0.00	4,818		4,818		4,818
40	LD-015	LD-015		0.00	0.00	4,818		4,818		4,818
41	LD-002	LD-002		0.00	0.00	207.1		207.1		207.1
42	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
43	LD-MSS	LD-MSS		0.00	0.00	0.01		0.01		0.01
Combined Cycle Turbine Sources										
44	7K	7K		0.00	0.00	524,520		524,520		524,520
45	7L	7L		0.00	0.00	524,520		524,520		524,520
46	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	1.24		1.24		1.24
47	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
48	SF6-FUG	SF6-FUG		0.00	0.00	<0.01		0.01		0.01

Notes: **Total =** **4,027,334**

[1] Elevated flare emission rate includes MSS emissions from vessel degassing.

[2] Baseline period is January 2009 through December 2010.

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant[1]:	CO2e	**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A

Affected or Modified Facilities[2]			Permit No.	Actual Emissions[3]	Baseline Emissions[4]	Proposed Emissions[5]	Projected Actual Emissions	Difference (B - A) [6]	Correction [7]	Project Increase[8]
	FIN	EPN			A	B				
Olefins 3 Plant Sources										
1	OL3-FUR1	OL3-FUR1		0.00	0.00	125,410		125,410		125,410
2	OL3-FUR2	OL3-FUR2		0.00	0.00	125,410		125,410		125,410
3	OL3-FUR3	OL3-FUR3		0.00	0.00	125,410		125,410		125,410
4	OL3-FUR4	OL3-FUR4		0.00	0.00	125,410		125,410		125,410
5	OL3-FUR5	OL3-FUR5		0.00	0.00	125,410		125,410		125,410
6	OL3-FUR6	OL3-FUR6		0.00	0.00	125,410		125,410		125,410
7	OL3-FUR7	OL3-FUR7		0.00	0.00	125,410		125,410		125,410
8	OL3-FUR8	OL3-FUR8		0.00	0.00	125,410		125,410		125,410
9	OL3-FUR9	OL3-FUR9		0.00	0.00	125,410		125,410		125,410
10	OL3-FUR10	OL3-FUR10		0.00	0.00	125,410		125,410		125,410
11	OL3-FUR11	OL3-FUR11		0.00	0.00	125,410		125,410		125,410
12	OL3-FUR12	OL3-FUR12		0.00	0.00	125,410		125,410		125,410
13	OL3-FUR13	OL3-FUR13		0.00	0.00	125,410		125,410		125,410
14	OL3-FUR14	OL3-FUR14		0.00	0.00	125,410		125,410		125,410
15	OL3-BOIL1	OL3-BOIL1		0.00	0.00	210,912		210,912		210,912
16	OL3-BOIL2	OL3-BOIL2		0.00	0.00	210,912		210,912		210,912
17	OL3-BOIL3	OL3-BOIL3		0.00	0.00	210,912		210,912		210,912
18	OL3-BOIL4	OL3-BOIL4		0.00	0.00	210,912		210,912		210,912
19	PDH-REAC1	PDH-REAC1		0.00	0.00	59,726		59,726		59,726
20	PDH-REAC2	PDH-REAC2		0.00	0.00	59,726		59,726		59,726
21	PDH-REAC3	PDH-REAC3		0.00	0.00	59,726		59,726		59,726
22	PDH-REAC4	PDH-REAC4		0.00	0.00	59,726		59,726		59,726
23	OL3-FUG	OL3-FUG		0.00	0.00	96.49		96.49		96.49
24	PDH-FUG	PDH-FUG		0.00	0.00	19.50		19.50		19.50
25	OL3-FLRA, OL3-FLRB	OL3-FLRA, OL3-FLRB		0.00	0.00	83,970	See Note 1	83,970		83,970

TABLE 2F
PROJECT EMISSION INCREASE

Pollutant(1):	CO2e		**Permit:**	TBD
Baseline Period:	N/A	**to**	N/A	

Affected or Modified Facilities(2)			Permit No.	Actual Emissions(3)	A Baseline Emissions(4)	B Proposed Emissions(5)	Projected Actual Emissions	Difference (B - A) (6)	Correction (7)	Project Increase(8)
	FIN	EPN								
26	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	1,157.7		1,157.7		1,157.7
27	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	1,157.7		1,157.7		1,157.7
28	OL3-DK1	OL3-DK1		0.00	0.00	329.1		329.1		329.1
29	OL3-DK2	OL3-DK2		0.00	0.00					
30	OL3-MAPD	OL3-MAPD		0.00	0.00	32.82		32.82		32.82
31	PDH-MSSVO	PDH-MSSVO		0.00	0.00	8.20		8.20		8.20
32	OL3-MSSVO	OL3-MSSVO		0.00	0.00	46.0		46.0		46.0
33	OL3-GEN	OL3-GEN		0.00	0.00	448.5		448.5		448.5
34	PDH-GEN	PDH-GEN		0.00	0.00	448.5		448.5		448.5
35	N6460FA/B	1087		2.72	2.72	3.29	See Note 2	0.57		0.57
LDPE Plant Sources										
36	LD-022A/B	LD-022A/B		0.00	0.00	32,306		32,306		32,306
37	LD-023A/B	LD-023A/B		0.00	0.00					
38	OL3-FLR	OL3-FLR		0.00	0.00	22,216	See Note 1	22,216		22,216
39	LD-014	LD-014		0.00	0.00	17,810		17,810		17,810
40	LD-015	LD-015		0.00	0.00	17,810		17,810		17,810
41	LD-002	LD-002		0.00	0.00	229.1		229.1		229.1
42	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
43	LD-MSS	LD-MSS		0.00	0.00	0.08		0.08		0.08
Combined Cycle Turbine Sources										
44	7K	7K		0.00	0.00	525,024		525,024		525,024
45	7L	7L		0.00	0.00	525,024		525,024		525,024
46	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	25.1		25.1		25.1
47	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
48	SF6-FUG	SF6-FUG		0.00	0.00	29.6		29.6		29.6
	Summary of Contemporaneous Changes							**Total**		**4,067,332**

Notes:

[1] Elevated flare emission rate includes MSS emissions from vessel degassing.

[2] Baseline period is January 2009 through December 2010.

APPENDIX C

CCS DETAILED BACT ANALYSIS AND SUPPLEMENTAL INFORMATION

BACT FOR CARBON CAPTURE AND SEQUESTRATION

FPC TX addresses the potential to capture GHG emissions that are emitted from Carbon Capture and Sequestration (CCS) candidate sources associated with the 2012 Expansion Project listed below (plant names in parenthesis):

- 14 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE)

The EPA five step top down BACT evaluation for this potential control technology options is provided in this Appendix. As shown in that analysis, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as a BACT option for any of the emissions sources associated with the 2012 Expansion Project.

6.1.1 STEP 1: IDENTIFY ALL AVAILABLE CONTROL TECHNOLOGIES

The emerging carbon capture and sequestration (CCS) technologies generally consist of processes that separate CO_2 from combustion or process flue gas (capture component), the compression and transport component, and then injection into geologic formations such as oil and gas reservoirs, unmineable coal seams, and underground saline formations (sequestration component). These three components of CCS are addressed separately below:

Carbon Capture:

Of the emerging CO_2 capture technologies that have been identified, only amine absorption is currently commercially used for state-of-the-art CO_2 separation processes. 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. Although the DOE-NETL discussions focus on CCS application at combustion units in electrical generation service, elements of this discussion are applicable when discussing the application of CCS to sources in the chemical manufacturing industry. The following excerpts from DOE-NETL Information Portal illustrate some of the many challenges, but not all, that are present in applying available CO_2 Capture technologies at combustion and process sources located at chemical manufacturing 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 power plants 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 power plant exhaust streams—about 90 percent removal—but the highly energy-intensive process of regenerating the solvents decreases plant electricity output…*[1]

In its CCS information portal, 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 turbines) 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.*

It should be noted that the majority of the candidate CCS source vent streams (previously listed in this section) are dilute in CO_2 concentration and contain impurities such as PM, NO_X and SO_2, thus increasing the challenge of CO_2 separation for the Point Comfort expansion project.

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[1] 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 July 26, 2012).

Compression and Transport:

The compression aspect of this component of CCS will represent a significant cost and additional environmental impact because of the energy required to provide the amount of compression needed. This is supported by DOE-NETL who states that:

> *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…*[2]

If CO_2 capture and compression can be achieved at a process or 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 of a geologic formation and CO_2 trapping mechanisms 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 and their associated technical challenges 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…*[3]

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[2] *Id.*

[3] DOE-NETL, *Carbon Sequestration: Geologic Storage Focus Area,* http://www.netl.doe.gov/technologies/carbon_seq/corerd/storage.html (last visited July 26, 2012)

Therefore, as can be seen from the DOE-NETL Information Portal, CCS as a whole cannot be considered a commercial available, technically feasible option for the combustion and process vent emissions sources under review in the FPC TX proposed expansion. FPC TX's expansion project generates flue gas streams that contain CO_2 in dilute concentrations and the project is not located in an acceptable geological storage location. Even so, FPC TX provides even further and more detailed evaluation to address all 5 steps of the EPA BACT analysis.

6.1.2 STEP 2: ELIMINATE TECHNICALLY INFEASIBLE OPTIONS

Although, as described above, CCS should not be considered an available control technology, in this section, FPC-TX addresses, in more detail, the potential feasibility of implementing CCS technology as BACT for GHG emissions from the proposed expansion project GHG emission sources. The feasibility issues are different for each component of CCS technology (i.e., capture; compression and transport; and storage). Therefore, technical feasibility of each component is addressed separately below.

6.1.2.1 CO_2 Capture

Though amine absorption technology for CO_2 capture has routinely been applied to processes in the petroleum refining and natural gas processing industries it has not been applied to process vents at chemical manufacturing plants.

The Obama Administration's Interagency Task Force on Carbon Capture and Storage, in its recently completed report on the current status of development of CCS systems for power plants, states that carbon capture could be used on combustion units. However, the following discussion on carbon capture technology availability for high volume vent streams and large combustion unit shows that carbon capture is not commercially available for application.

Large commercial applications, such as the expansion project sources, present even more difficult application of carbon capture, in part, due to the additional variability in flow volumes as typically experienced in chemical plants. Therefore, the discussion related to power plants also shows that of CO_2 capture for chemical process combustion and process vent stream are not commercially available.

> *Current technologies could be used to capture CO_2 from new and existing fossil energy power plants; however, they are not ready for widespread implementation primarily because they have not been demonstrated at the scale necessary to establish confidence for power plant application. Since the CO_2 capture capacities used in current industrial processes are generally much smaller than the capacity required for the purposes of GHG emissions mitigation at a typical power plant, there is considerable uncertainty associated with capacities at volumes necessary for commercial deployment*.[4]

In its current CCS research program plans (which focus on power plant application), the DOE-NETL confirms that commercial CO_2 capture technology for large-scale combustion units (e.g., power plants) is not yet available and suggests that it may not be available until at least 2020:

> *The overall objective of the Carbon Sequestration Program is to develop and advance CCS technologies that will be ready for widespread commercial deployment by 2020. To accomplish widespread deployment, four program goals have been established:*
>
> > *(1) Develop technologies that can separate, capture, transport, and store CO_2 using either direct or indirect systems that result in a less than 10 percent increase in the cost of energy by 2015;*
> >
> > *(2) Develop technologies that will support industries' ability to predict CO_2 storage capacity in geologic formations to within ±30 percent by 2015;*
> >
> > *(3) Develop technologies to demonstrate that 99 percent of injected CO_2 remains in the injection zones by 2015;*
> >
> > *(4) Complete Best Practices Manuals (BPMs) for site selection, characterization, site operations, and closure practices by 2020. Only by accomplishing these goals will CCS technologies be ready for safe, effective commercial deployment both domestically and abroad beginning in 2020 and through the next several decades.*[5A]

To corroborate that commercial availability of CO_2 capture technology for large-scale combustion (power plant) projects will not occur for several more years, Alstom, one of the major developers of commercial CO_2 capture technology using post-combustion amine absorption, post-combustion chilled ammonia absorption, and oxy-combustion, states on its web

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[4] *Report of the Interagency Task Force on Carbon Capture and Storage* at 50 (Aug. 2010).

[5] DOE-NETL, *Carbon Sequestration Program: Technical Program Plan,* at 10 (Feb. 2011).

site that its CO_2 capture technology will become commercially available in 2015.[6] However, it should be noted that in committing to this timeframe, the company does not indicate whether such technology will be available for CO_2 emissions generated from chemical plant sources, like those included in the Point Comfort expansion project.

6.1.2.2 CO_2 Compression and Transport

Notwithstanding the fact that the above discussion demonstrates that the carbon capture component of CCS is not commercial available for chemical plant combustion and process vents, FPC TX provides the following discussion concerning technical feasibility. This discussion further supports that the compression and transport component of CCS may be technically feasible but, as explained later, the cost evaluation shows that it is not economically reasonable. Therefore, CCS is not BACT for the 2012 Expansion Project.

Even if it is assumed that CO_2 capture could feasibly be achieved for the proposed project, the high-volume CO_2 stream generated would need to be compressed and transported to a facility capable of storing it. Potential geologic storage sites in Texas, Louisiana, and Mississippi to which CO_2 could be transported if a pipeline was constructed are delineated on the map found at the end of this Appendix.[7] The hypothetical minimum length required for any such pipeline(s) is the distance to the closest site with recognized potential for some geological storage of CO_2, which is an enhanced oil recovery (EOR) reservoir site located within 15 miles of the proposed project. However, none of the South and Southeast Texas EOR reservoir or other geologic formation sites have yet been technically demonstrated for large-scale, long-term CO_2 storage.

In comparison, the closest site that is currently being field-tested to demonstrate its capacity for large-scale geological storage of CO_2 is the Southwest Regional Partnership (SWP) on Carbon Sequestration's Scurry Area Canyon Reef Operators (SACROC) test site, which is located in Scurry County, Texas approximately 370 miles away (see the map at the end of this Appendix for the test site location). Therefore, to access this potentially large-scale storage capacity site,

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[6] Alstom, *Alstom's Carbon Capture Technology Commercially "Ready to Go" by 2015*, Nov.30, 2010, http://www.alstom.com/australia/news-and-events/pr/ccs2015/ (last visited July.26, 2012).

[7] Susan Hovorka, University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, *New Developments: Solved and Unsolved Questions Regarding Geologic Sequestration of CO_2 as a Greenhouse Gas Reduction Method* (GCCC Digital Publication #08-13) at slide 4 (Apr. 2008), available at: http://www.beg.utexas.edu/gccc/forum/codexdownloadpdf.php?ID=100(last visited July 26, 2012).

assuming that it is eventually demonstrated to indefinitely store a substantial portion of the large volume of CO_2 generated by the proposed project, a very long and sizable pipeline would need to be constructed to transport the large volume of high-pressure CO_2 from the plant to the storage facility, thereby rendering implementation of a CO_2 transport system infeasible.

The potential length of such a CO_2 transport pipeline is uncertain due to the uncertainty of identifying a site(s) that is suitable for large-scale, long-term CO_2 storage. The hypothetical minimum length required for any such pipeline(s) is estimated to be the lesser of the following:

- The distance to the closest site with established capability for some geological storage of CO_2, which is an enhanced oil recovery (EOR) reservoir site[8] located more than 600 kilometers from the proposed project; or
- The distance to a CO_2 pipeline that Denbury Green Pipeline-Texas is currently constructing approximately 150 kilometers (straight line distance) from the project site for the purpose of providing CO_2 to support various EOR operations in Southeast Texas beginning in late 2013.

6.1.2.3 CO_2 Sequestration

Even if it is assumed that CO_2 capture and compression could feasibly be achieved for the proposed project and that the CO_2 could be transported economically, the feasibility of CCS technology would still depend on the availability of a suitable pipeline or sequestration site as addressed in Step 4 of the BACT analysis. The suitability of potential storage sites is a function of volumetric capacity of their geologic formations, CO_2 trapping mechanisms within formations (including dissolution in brine, reactions with minerals to form solid carbonates, and/or adsorption in porous rock), and potential environmental impacts 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,

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[8] None of the nearby South Texas EOR reservoirs or other geologic formation sites have been technically demonstrated for large-scale, long-term CO_2 storage.

- Risks of brine displacement resulting from large-scale CO_2 injection, including a pressure leakage risk for brine into underground drinking water sources and/or surface water,
- Risks to fresh water as a result of leakage of CO_2, including the possibility for damage to the biosphere, underground drinking water sources, and/or surface water,[9] 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. In comparison, the closest site that is currently being field-tested to demonstrate its capacity for geological storage of the volume of CO_2 that would be generated by the proposed power unit, i.e., SWP's SACROC test site, is located in Scurry County, Texas approximately 370 miles away. It should be noted that, based on the suitability factors described above, currently the suitability of the SACROC site or any other test site to store a substantial portion of the large volume of CO_2 generated by the proposed project has yet to be fully demonstrated.

6.1.3 STEP 3: RANK REMAINING CONTROL TECHNOLOGIES

As documented above, implementation of CCS technology for the FPC TX expansion emission sources is not currently commercially available or feasible for both technical and economic reasons. Even so, FPC TX will provide detailed economic and impacts analyses in Step 4 which provides further documentation for eliminating this option as a control Technology to be evaluated for the GHG emission sources associated with the FPC TX expansion.

6.1.4 STEP 4: EVALUATE MOST EFFECTIVE CONTROLS AND DOCUMENT RESULTS

6.1.4.1 Additional Environmental Impacts and Considerations

There are a number of other environmental and operational issues related to the installation and operation of CCS that must also be considered in this evaluation. First, operation of CCS capture and compression equipment would require substantial additional electric power. For

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[9] *Id.*

example, operation of carbon capture equipment at a typical natural gas fired combined cycle plant is estimated to reduce the net energy efficiency of the plant from approximately 50% (based on the fuel higher heating value (HHV)) to approximately 42.7% (based on fuel HHV).[10] To provide the amount of reliable electricity needed to power a capture system, FPC TX would need to significantly expand the scope of the utility plant expansion proposed with this project to install one or more additional electric generating units, which are sources of conventional (non-GHG) and GHG air pollutants themselves. To put these additional power requirements in perspective, gas-fired electric generating units typically emit more than 100,000 tons CO_2e/yr and would themselves, require a PSD permit for GHGs in addition to non-GHG pollutants.

FPC TX would need to construct a pipeline that is estimated to be at least 100 miles in length to transport captured GHGs to the nearest potential purchaser (Denbury Green Pipeline). Constructing a pipeline of this magnitude would require procurement of right-of-ways which can be a lengthy and potentially difficult undertaking. Pipeline construction would also require extensive planning, environmental studies and possible mitigation of environmental impacts from pipeline construction. Therefore, the transportation of GHGs for this project would potentially result in negative impacts and disturbance to the environment in the pipeline right-of-way.

Finally, implementation of CCS for the 2012 Expansion Project poses several operational and business concerns. First, the sale of CO_2 material to either a pipeline entity or to a storage facility (EOR) would be made under contractual terms. FPC TX is in the primary business of selling commodity and specialty chemicals; the sale of CO_2 would be a secondary product. The GHG sources that would be tied into a CCS system must be periodically taken out of service for maintenance or other reasons to ensure maximum yield of primary product from the production unit, thereby temporary eliminating or reducing the supply of CO_2 to the buyer. FPC TX has identified contractual issues relating to the sale of CO_2 that conflict directly with existing contracts relating to the sale of primary products. For this reason, FPC TX believes that the sale of CO_2 from the Point Comfort expansion sources poses an unacceptable business conflict.

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[10] US Department of Energy, National Energy Technology Laboratory, “Costs and Performance Baseline For Fossil Energy Plants, Volume 1 - Bituminous Coal and Natural Gas to Energy”, Revision 2, November 2010

6.1.4.2 CCS Cost Evaluation

Based on the reasons provided above, FPC TX believes that CCS technology should be eliminated from further consideration as a potential feasible control technology for purposes of this BACT analysis. Furthermore, the Congressional Budget Office's June 2012 document entitled *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide* states that "average capital costs for a CCS-equipped plant would be 76 percent higher than those for a conventional plant."[11] Even so, to address possible questions that the public or the EPA may have concerning the relative costs of implementing hypothetical CCS systems, FPC TX has estimated such costs.

For the cost evaluation, FPC TX considered all plants project (Olefins Expansion, LDPE plant and gas turbines) associated the expansion GHG emission sources for which CCS is considered technically feasible, for purposes of this analysis, even though separate permits are requested for each plant. These GHG emissions sources include the following emission units (respective plant names/permit applications shown in parenthesis):

- 14 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- 2 combined cycle gas-fired turbines (Gas Turbines)
- 2 regenerative thermal oxidizers (LDPE Plant)

FPC TX's cost estimation is conservatively low because it does not include additional costs for the following items that would be needed to implement CCS for the FPC TX 2012 Expansion Project:

- additional gas conditioning and stream cleanup to meet specifications for final sale
- thousands of feet of gas gathering system piping to collect vent gas from sources located in different operating units
- costs of additional electric generating units required to power the capture and compression system (including design, procurement, permitting, installation, operating and maintenance costs)
- cost of obtaining rights of way for construction of a pipeline

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[11] *Federal Efforts to Reduce the Cost of Capturing and Storing Carbon Dioxide,* Page 7 (June 2012).

These items would require significantly more effort to estimate and, since the conservatively low cost estimate demonstrates that this technology is not economically reasonable, it was not necessary to expend the extra time and resources to gather this additional data for the cost analysis.

The CCS system cost estimate, excluding these additional capital expenditure items, is presented on Table 6-1 at the end of this Appendix. The total CCS system cost is estimated at over 300 million dollars, which is more than 15% of the total Point Comfort expansion project capital cost (total estimated capital cost is 2 billion dollars). Based on the Congressional Budget Office's indications, this estimate of cost as a percentage of the total capital investment is conservatively low. Increasing the capital cost of the expansion project by this margin and increasing the ongoing operating and maintenance costs would render this project economically unviable. The margins of additional capital and operating costs are significantly greater if the aforementioned additional capital cost items, which were excluded, are taken into consideration.

As discussed above, CCS was determined to be not commercially available and not technically feasible; therefore, a detailed examination of the energy, environmental, and economic impacts of CCS is not required for this application. However, at the request of EPA Region 6, FPC-TX included the estimated costs for implementation of CCS which are presented in Table 6-1. As discussed above these costs show that CCS is not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5 STEP 5: SELECT BACT

As demonstrated in Steps 2 and 4 of the BACT review, CCS is not only not commercially available, not technically feasible but also economically unreasonable. Therefore, it is not included as BACT for the FPC TX expansion.

6.1.5.1 CCS in Other GHG Permits

FPC TX searched GHG permits issued by EPA Region 6 and other states. Only one permit included the use of CCS, the Indiana Gasification, LLC (IG) project, permit no. 147-30464-00060 issued by the Indiana Department of Environmental Management (IDEM). The IG project proposes the construction of a coal gasification power plant that will produce liquefied carbon dioxide which will be compressed and piped several hundred miles to EOR facilities in the Gulf Coast region.

This project differs significantly from the Point Comfort expansion in most technical aspects, but it should also be noted that IG has secured federal loan guarantees and potentially state tax credits to make the project, including application of CCS, economically viable. Furthermore, on page 154 of 181 of the PSD/TV Permit, Step 4 of the GHG BACT evaluation for the acid gas removal units (the primary GHG emission vents) state that:

> *IG will not begin construction of this facility without a fully financed project agreement for the pipeline that provides for the pipeline to be in place and ready to receive liquefied CO_2 at the point when pipeline quality CO_2 is available.*

This statement provides evidence that the project, including application of CCS, hinges on the approval and contracts for a new CO_2 pipeline. It is clear from the following quote from the Indiana permit application that installation of CCS was not justified for this project as BACT. The GHG BACT evaluation for the proposed IG plant concludes that “Based on the technically feasibility analysis in Step 2, there are no viable control technologies for the control of GHG emissions from the acid gas recovery unit vent.” This is consistent with the results of FPC TX’s BACT analysis of CCS for the Point Comfort Expansion project.

Table 6-1
Range of Approximate Annual Costs for Installation and Operation of Capture, Transport, and Storage Systems for Control of CO_2 Emissions from the Point Comfort Expansion

Carbon Capture and Storage (CCS) Component System	Factors for Approximate Costs for CCS Systems	Annual System CO_2 Throughput (tons of CO_2 captured, transported, and stored) [1]	Pipeline Length for CO_2 Transport System (km CO_2 transported) [5]	Range of Approximate Annual Costs for CCS Systems ($)
Post-Combustion CO_2 Capture and Compression System				
Minimum Cost	$44.11 / ton of CO_2 avoided [2]	3,958,848		$174,624,801
Maximum Cost	$103.42 / ton of CO_2 avoided [3]	3,958,848		$409,420,359
Average Cost	$73.76 / ton of CO_2 avoided [4]	3,958,848		$292,022,580
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [3]	3,958,848	150	$5,387,110
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [3]	3,958,848	150	$16,161,330
Average Cost	$1.81 / ton of CO_2 transported per 100 km [4]	3,958,848	150	$10,774,220
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [3, 6]	3,958,848		$2,011,188
Maximum Cost	$18.14 / ton of CO_2 stored [3, 6]	3,958,848		$71,828,133
Average Cost	$9.33 / ton of CO_2 stored [4]	3,958,848		$36,919,660
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$45.98 / ton of CO_2 removed	3,958,848		$182,023,099
Maximum Cost	$125.65 / ton of CO_2 removed	3,958,848		$497,409,822
Average Cost	$85.81 / ton of CO_2 removed [4]	3,958,848		$339,716,460

[1] Assumes the maximum possible annual CO_2 emissions scenario and assumes that a capture system would be able to capture 90% of the total CO_2 emissions generated by the combustion turbines.

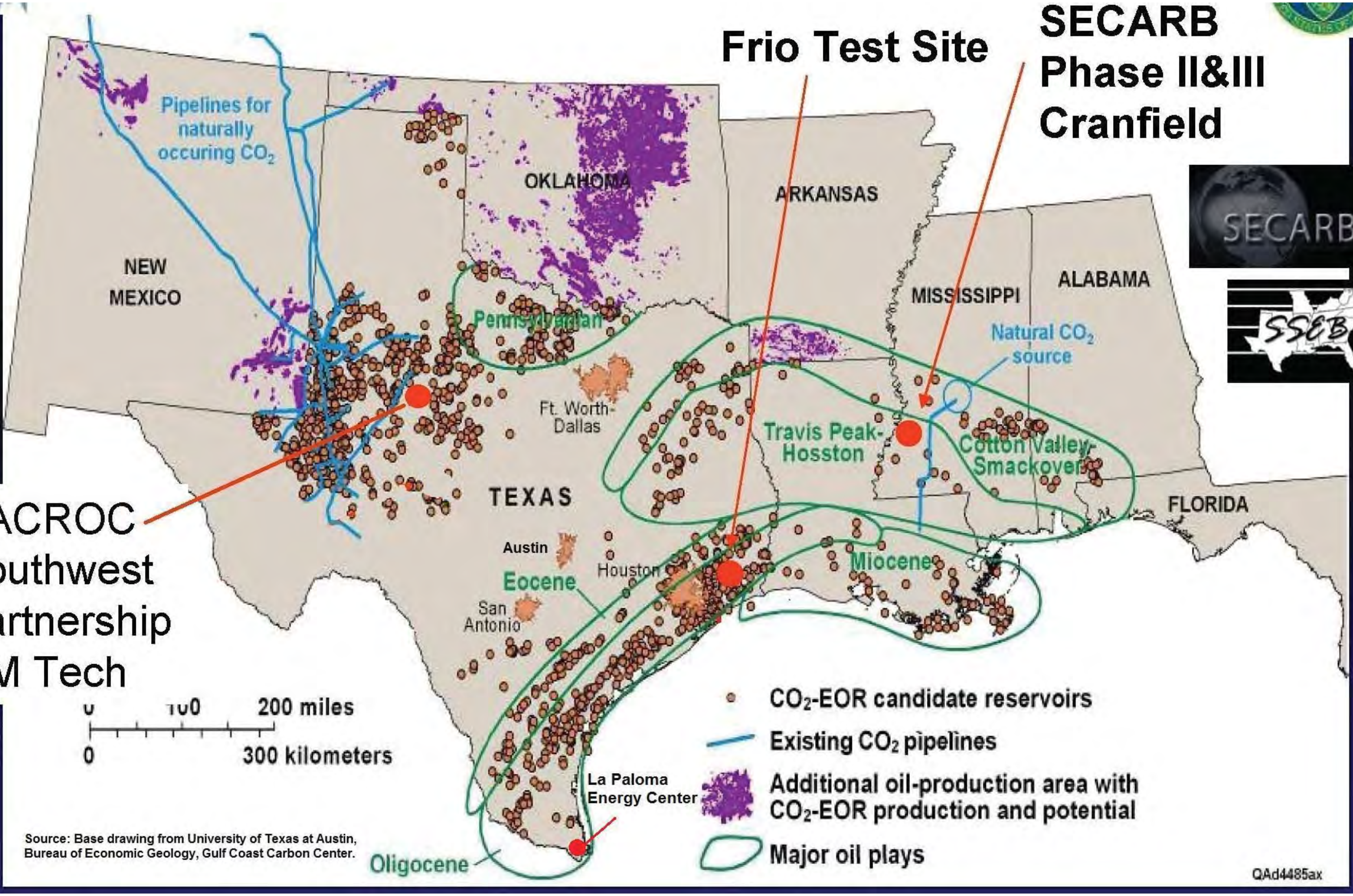
[2] This cost factor is the minimum found for implementation/operation of CO_2 capture systems within the cost-related information reviewed for CCS technology. The factor is from the on the "Properties" spreadsheet of the *Greenhouse Gas Mitigation Strategies Database* (Apr. 2010) (http://ghg.ie.unc.edu:8080/GHGMDB/#data), which was obtained through the EPA GHG web site (http://www.epa.gov/nsr/ghgpermitting.html). The factor is based on the increased cost of electricity (COE; in $/MW-h) resulting from implementation and operation at a CO_2 capture system on a natural gas-fired combined cycle power plant. The factor accounts for annualized capital costs, fixed operating costs, variable operating costs, and fuel costs.

[3] These cost factors are from *Report of the Interagency Task Force on Carbon Capture and Storage* , pp.33, 34, 37, and 44 (Aug. 2010) (http://www.epa.gov/climatechange/policy/ccs_task_force.html). The factors from the report in the form of $/tonne of CO_2 avoided, transported, or stored and have been converted to $/ton. Per the report, the factors are based on the increased cost of electricity (COE; in $/kW-h) of an "energy-generating system, including all the costs over its lifetime: initial investment, operations and maintenance, cost of fuel, and cost of capital".

[4] The average cost factors were calculated as the arithmetic mean of the minimum and maximum factors for each CCS component system and for all systems combined.

[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at: http://www.beg.utexas.edu/gccc/graphics/Basemap_state_lands_fp_lg.jpg (last visited Feb. 27, 2012).

[6] "Cost estimates [for geologic storage of CO_2] are limited to capital and operational costs, and do not include potential costs associated with long-term liability." (from the *Report of the Interagency Task Force on Carbon Capture and Storage* , p. 44)



Frio Test Site

SECARB Phase II&III Cranfield

SACROC
Southwest Partnership
NM Tech

Source: Base drawing from University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center.

APPENDIX D

KELLY HART & HALLMAN MEMO
RE: EPA POLICY ON MULTIPLE PSD PERMITS

KELLY HART &
HALLMAN
A PROFESSIONAL CORPORATION

MEMORANDUM

To: Brian Tomasovic

From: Bob Stewart and Steve Dickman

Date: July 13, 2012

Re: EPA Policy on Obtaining Multiple PSD Permits for a Single Source

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I. Purpose of Memo and Short Answer

Factual Summary: Formosa Plastics Corp. ("FPC") intends to apply for federal Clean Air Act prevention of significant deterioration ("PSD") greenhouse gas permitting authorization from EPA for its olefins expansion project. This single project consists of three new related major greenhouse gas emission sources at its Point Comfort facility which should be authorized under three separate PSD permits, rather than under a single PSD permit. The first PSD permit will cover greenhouse gas emissions from the proposed new olefins 3 cracker and an associated propane dehydrogenation (PDH) unit; the second PSD permit will cover greenhouse gas emissions from a proposed new low density polyethylene (LDPE) resin plant; and the third PSD permit will cover greenhouse gas emissions from a new power utilities facility serving the other new units. Applying for three new PSD permits is desired by FPC for administrative and compliance reasons including organizational responsibility and accountability within FPC. In support of this approach, TCEQ has historically permitted FPC's various production facilities under separate PSD permits for criteria pollutants. FPC will subject all new units in the aggregate to normal PSD permitting requirements including application of BACT and fenceline air quality impacts analysis.

Issue: This proposal raises the question of whether it is permissible under EPA rules or policy guidance for FPC to obtain permitting of the new units under multiple PSD permits within a single PSD action rather than under a single PSD permit.

Short Answer: EPA has consistently stated that authorizing separate units at a major source facility under separate PSD permits is acceptable so long as doing so does not circumvent the full spectrum of PSD permitting requirements that would apply if the units were jointly permitted under a single permit.

II. Background Controversy Regarding the Aggregation Issue

The issue of use of multiple PSD permits most commonly arises in the context of the PSD Aggregation issue which is the question of whether multiple physical or operational changes must be grouped together, or "aggregated", as a single physical or operational change for purposes of determining applicability of PSD review. Typically, the Aggregation issue arises when a facility attempts to expedite a construction project by applying for several minor source permits for facility changes in order to evade or circumvent the more detailed PSD review that would occur if the changes were considered as a single "major source" PSD project or major modification. The Aggregation issue is important because of consequences in terms of higher costs and level of regulatory review associated with undergoing full PSD review.

EPA typically considers this issue on a case-by-case basis under three regulatory factors set forth in EPA rules along with a set other relevant factors identified in various EPA letters and memoranda. EPA rules as set forth in the definitions of "stationary source" and "building, structure, facility or installation" in 40 CFR Part 52 provide that two or more nominally-separate facility changes should be considered a single PSD project if they meet all of the following three criteria:

1. They belong to the same SIC major (2-digit) group. If two different project facilities could have separate SIC codes but a support relationship exists (e.g., 50% or more of the product of one facility is utilized by the other facility) then one facility is considered a support facility and this criterion is deemed to have been met.

2. They are located on one or more contiguous or adjacent properties in the same general area.

3. They are under common ownership or control. (If this is in dispute, then EPA will review any contractual agreements between the facilities to determine if they are under common control.)

Other various factors used by EPA in conjunction with the above test include:

- the closeness in time to the filing of applications for nominally-separate facility changes;
- whether the nominally-separate changes were considered together in the permittee's integrated facility planning documents or in financing proposals or in public statements;
- whether the nominally-separate facility changes are operationally dependent on each other;
- whether the nominally-separate facility changes are substantially related to each other in some other way;
- whether it is feasible for the permittee to operate a proposed facility change as a minor source without the other facility changes.

The purpose of EPA's Aggregation Policy is to prevent circumvention of PSD review. If multiple facility changes must undergo PSD review as a single PSD project then all relevant facility changes are considered together and are typically authorized under a single PSD permit. However, EPA has recognized that if the Aggregation Policy is so applied, all facilities need not necessarily be authorized under a single PSD permit.

III. Obtaining Separate PSD Permits for Separate Projects

A. The Nucor Case. The most recent expression of EPA policy on the subject of the Aggregation Policy and the use of multiple permits is an EPA Title V permit protest order signed by Lisa Jackson on March 23, 2012 in the case of Nucor Steel of Louisiana. In that case (copy attached), EPA granted three petitions for review of three Title V permits proposed to be issued to Nucor on the grounds that the Title V permits did not properly incorporate NSR permitting requirements as established in the Louisiana SIP. Specifically, the Louisiana Department of Environmental Quality ("LDEQ") had issued separate PSD permits and separate Title V permits to Nucor's pig iron process and its direct reduced iron ("DRI") manufacturing process both of which processes were located at a single site (in a NSR attainment area).

In its objections to Nucor's Title V permits, Zen-Noh Grain Corporation noted that even though both the pig iron process and the DRI process units would each be subject to BACT, LDEQ's proposal to allow separate PSD permitting of the two processes would circumvent the air quality impact analysis prerequisites for the entire Nucor facility. For example, for SO_2 and PM_{10}/$PM_{2.5}$ Nucor modeled only emissions from the DRI process and determined them to be below the significant impact level ("SIL") PSD threshold, but Zen-Noh's modeling showed that if aggregate emissions were modeled a full National Ambient Air Quality Standards ("NAAQS") analysis would have been required for SO_2 and PM_{10} and $PM_{2.5}$, and that the combined Nucor facility would cause a violation of NAAQS for these pollutants.

Pages 8 through 14 of the EPA Order discusses EPA's rationale for determining that emissions from both processes at Nucor should be aggregated. For the most part, EPA's rationale was that LDEQ had not sufficiently demonstrated why the two facilities should be considered separate sources. However, EPA made clear that even though Nucor was not attempting to avoid PSD review for either process since each process was individually a major source, "Nucor's ambient air quality impacts analysis did not consider whether the combined emissions from both the pig iron and DRI processes for all pollutants call for a more thorough cumulative analysis of the air quality impact of these sources." Thus, EPA did not object to the authorization of separate projects under separate PSD and Title V permits, it only objected to Nucor's failure to demonstrate that the combined air impacts of the combined projects met PSD requirements as would have been demonstrated if the two processes were considered in the aggregate.

B. Other EPA Policy Statements. In other cases, the EPA has indicated that having multiple PSD permits for a single PSD project is acceptable so long as doing so does not result in circumvention of PSD requirements that would otherwise apply.

In an EPA objection to Colorado's proposed Title V permit to TriGen-Colorado Energy Corporation which operates a power plant located at, and exclusively serving, the Coors Brewery, EPA required that the permittee's air emissions be aggregated with those of the Coors Brewery for PSD and Title V permitting purposes even though TriGen and Coors had separate PSD and Title V permits. EPA stated that "future modifications of the two facilities that make up a single source must be addressed together to calculate net emissions increases for comparison with NSR and PSD significance levels."

In a 2001 case concerning PSD applicability, EPA issued a determination that two adjacent and commonly-owned power generating facilities could be permitted separately as minor sources because regardless of whether the facilities each obtained a minor NSR permit, the permits would require BACT so that the facilities were not circumventing NSR emission control requirements by obtaining minor source permits. See, Oct. 12, 2001 letter "PSD Applicability for Frederickson Power, L.P." from Doug Cole, Acting Manager Federal & Delegated Air Programs Unit, EPA Region 10 to Grant Cooper and Raymond McKay.

In several cases where EPA has determined that co-located facilities should be aggregated, it has also specified that the facilities need not share a common Title V operating permit. For example, in a November 27, 1996 letter to Jennifer Schlosstein at Simpson Paper Company from Matt Haber of EPA Region 9, EPA stated "There is no need for Simpson and SMI to certify or assure compliance over each other in a Title V permit. EPA recommends that even though they are considered one source, each facility apply for a separate Title V permit, each with its own responsible official, under the Title V application process."

On August 2, 1996, EPA's Office of Air Quality Planning and Standards issued a policy memo concerning "Major Source Determinations for Military Installations" in which EPA stated:

> "After determining that stationary sources at a military installation are subject to Title V permitting, permitting authorities have discretion to issue more than one Title V permit to each major source at that installation, so long as the collection of permits assures that all applicable requirements would be met that otherwise would be required under a single permit for each major source."

EPA explained its rationale for allowing multiple Title V permits for different projects within a single facility in its November 15, 2002 order denying a petition for objection to the Title V permit for Shaw Industries in Georgia. According to the Georgia Environmental Protection Division, for administrative reasons Shaw requested that three separate Title V permits be issued for three different but co-located plants at the Shaw carpet manufacturing facility in Dalton, Georgia. EPA stated in its order:

> "Although multiple facilities meeting the definition of 'same source' must be evaluated as one source with respect to applicability, nothing in the CAA or Part 70 prohibits permitting authorities from issuing multiple Title V permits to one Part 70 source….. Thus under the CAA and EPA's regulations, a Part 70 source is free to request that it be issued more than one Part 70 permit, and permitting authorities are not prohibited from issuing multiple permits to facilities that together constitute a single source. However, permitting authorities that issue multiple permits should do so in a way that makes each facility's compliance obligations clear. Each permit narrative or statement of basis should refer to the other permits and explain the relationships between the facilities for purposes of applicability determinations. For instance, each permit narrative should indicate whether any changes at one facility may require offsetting measures at another facility."

Although the above EPA policy statements in the three immediately preceding cases specifically concern Title V permits, there is no reason why the same rationale should not apply to NSR and PSD permits, especially since EPA has specifically so ruled in the Nucor, TriGen and Frederickson cases discussed above.

IV. Conclusion

Based on the above-cited policy rulings, EPA has clearly accepted the practice of issuing PSD permits for multiple units located at a single major source facility. Separate PSD permits may be issued for separate units within a single PSD project so long as the issuance of separate permits does not allow the units in the aggregate to circumvent any regulatory requirements that would apply if the units were permitted in one permit as a single source .

In the case of FPC, although EPA's Aggregation Policy would clearly apply so as to require FPC to aggregate the emissions from its proposed new facility units, all of those emissions will undergo the full spectrum of PSD review in the aggregate. So long as FPC applies BACT to the new units and performs the required PSD air impacts analysis on an aggregated basis for all of the new units, the use of three separate PSD permits for a single PSD project is acceptable under past EPA practice. In addition, FPC will address any future modifications by evaluating the upstream and downstream effects of the modification on any one or more of the three PSD permits (and other permits) in order to determine the PSD significance thresholds for the modification permitting action. Consequently, the PSD analysis for future modifications would not in any way be circumvented by the fact that three PSD permits are in effect, but rather FPC will evaluate all increases in actual emissions resulting from the modification. Finally, as indicated in the Shaw Industries case, the reasons for utilizing multiple permits may simply be for purposes of administrative convenience of the permittee. In this case, FPC is requesting three separate PSD permits, each of which would be covered under individual Title V permits, in order to comply with future CAA certification requirements and maintain accountability. FPC uses a system designed to assure, through each unit's "chain of command," that the statements and information submitted are true, accurate and complete. Accordingly, EPA should have no legal or practical reasons for objecting to authorization of FPC's new single project for three new units under three separate PSD greenhouse gas permits.