Formosa Plastics

Formosa Plastics Corporation, Texas
201 Formosa Drive • P.O. Box 700
Point Comfort, TX 77978
Telephone: 361-987-7000

November 30, 2012

Certified Mail Number: 7011 0110 0000 1782 9978

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

RE: Greenhouse Gas Permit Application
2012 Expansion Project
LDPE Plant
Formosa Plastics Corporation, Texas
Point Comfort, Calhoun County, Texas

Dear Mr. Robinson:

Formosa Plastics Corporation, Texas (FPC TX) currently operates a number of chemical plants at a chemical complex in Point Comfort, Calhoun County, Texas. As we discussed during our June 27, 2012 meeting in your office, FPC TX proposes to expand the FPC TX chemical complex within the existing Point Comfort site footprint. This 2012 Expansion Project will consist of a new Low Density Polyethylene (LDPE) plant, an Olefins Expansion (a new Olefins 3 plant and an associated Propane Dehydrogenation (PDH) unit), and two new Combined Cycle Turbines (Gas Turbines).

As described in the July 13, 2012 Kelly Hart & Hallman memo to Mr. Brian Tomasovic of EPA, the 2012 Expansion Project consists of the three new related plants (identified above) which comprise a single greenhouse gas Prevention of Significant Deterioration (PSD) project. In order to align FPC TX organizational responsibility and accountability for compliance with future permit requirements related to these plants, FPC TX is requesting three separate permits for the proposed new plants. 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 plants.

This letter transmits the FPC TX's application for a Greenhouse Gas (GHG) PSD permit for the LDPE plant at FPC TX's Point Comfort complex. The Olefins Expansion and Gas Turbine GHG permit applications are being submitted under separate cover to the EPA. The LDPE plant PSD application for criteria pollutant emissions is being be submitted to the Texas Commission on Environmental Quality (TCEQ).

General information for the application is provided on the TCEQ Form PI-1 - General Application for Air Preconstruction Permit and Amendments. The U.S. Environmental Protection Agency's (EPA) document entitled *"PSD and Title V Permitting Guidance for Greenhouse Gases", dated November 2010 and March 2011,* was utilized as a guide for preparation of the attached application.

FPC TX is committed to working closely with EPA Region 6 so that permit application review can be completed as expeditiously as possible. FPC TX anticipates the start of construction in the third quarter of 2013.
Also, as it relates to the permit review timelines, FPC TX would like to report on the progress that has been made on "cross-cutting" federal issues since our meeting in your offices on June 27, 2012. FPC TX has been in discussion with NOAA and USFWS concerning their expectations for assessments related to this expansion and will be addressing their specific concerns in our final biological assessment (BA). As you know, FPC TX has already performed a preliminary biological assessment analysis based on an action area with a radius of 7 miles around the FPC TX Point Comfort Site. Preliminary modeling indicates that the final action area based on final modeling can be expected to be less than 7 miles; therefore, FPC TX expects this preliminary BA analysis to be representative of the final analysis. FPC TX is in the process of finalizing the cultural resources assessment that will be provided to EPA for consultation with the State Historic Preservation Officer (SHPO).

Should you have any questions regarding this application, please contact Ms. Tammy Lasater of Formosa Plastics Corporation 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,

Randy P. Smith
Vice President/General Manager

Enclosure

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- Print your name and address on the reverse so that we can return the card to you.
- Attach this card to the back of the mailpiece, or on the front if space permits.

1. Article Addressed to:

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

EHS/tl

COMPLETE THIS SECTION ON DELIVERY

A. Signature
X
☐ Agent
☐ Addressee

B. Received by *(Printed Name)*

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☐ Insured Mail ☐ C.O.D.

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City, State, ZIP+4 *Dallas, Texas 75202-2733*

PS Form 3800, August 2006 See Reverse for Instructions

FORMOSA PLASTICS CORP., TEXAS
P.O. BOX 700
POINT COMFORT, TEXAS 77978
361/987-7000

To:

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

GREENHOUSE GAS PERMIT APPLICATION
PREVENTION OF SIGNIFICANT DETERIORATION:
2012 EXPANSION PROJECT
LOW DENSITY POLYETHYLENE (LDPE) 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

PREPARED BY:

ZEPHYR ENVIRONMENTAL CORPORATION
2600 VIA FORTUNA, SUITE 450
AUSTIN, TEXAS 78746

NOVEMBER 2012

zephyr

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APPENDICES

Appendix A – GHG Emission Calculations
Appendix B – PSD Netting Tables
Appendix C – CCS Detailed BACT Analysis and Supplemental Information
Appendix D - Kelly Hart & Hallman Memo Re: EPA Policy on Multiple PSD Permits

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 a two new Combined Cycle Turbines (Gas Turbines), an Olefins Expansion (a new Olefins 3 plant and a Propane Dehydrogenation (PDH) unit), and a new Low Density Polyethylene (LDPE) Plant.

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 LDPE plant 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 LDPE plant 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 LDPE project information for this GHG application. In addition, an overall expansion plot plan, LDPE plant plot plan, and 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 Permit 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: LDPE Plant - GHG	☒ 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 Permit 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
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Air Preconstruction Permit and Amendment
For EPA GHG Permit 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	

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 ☐		

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

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 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

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
Form PI-1 General Application for
Air Preconstruction Permit and Amendment
For EPA GHG Permit Application

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.

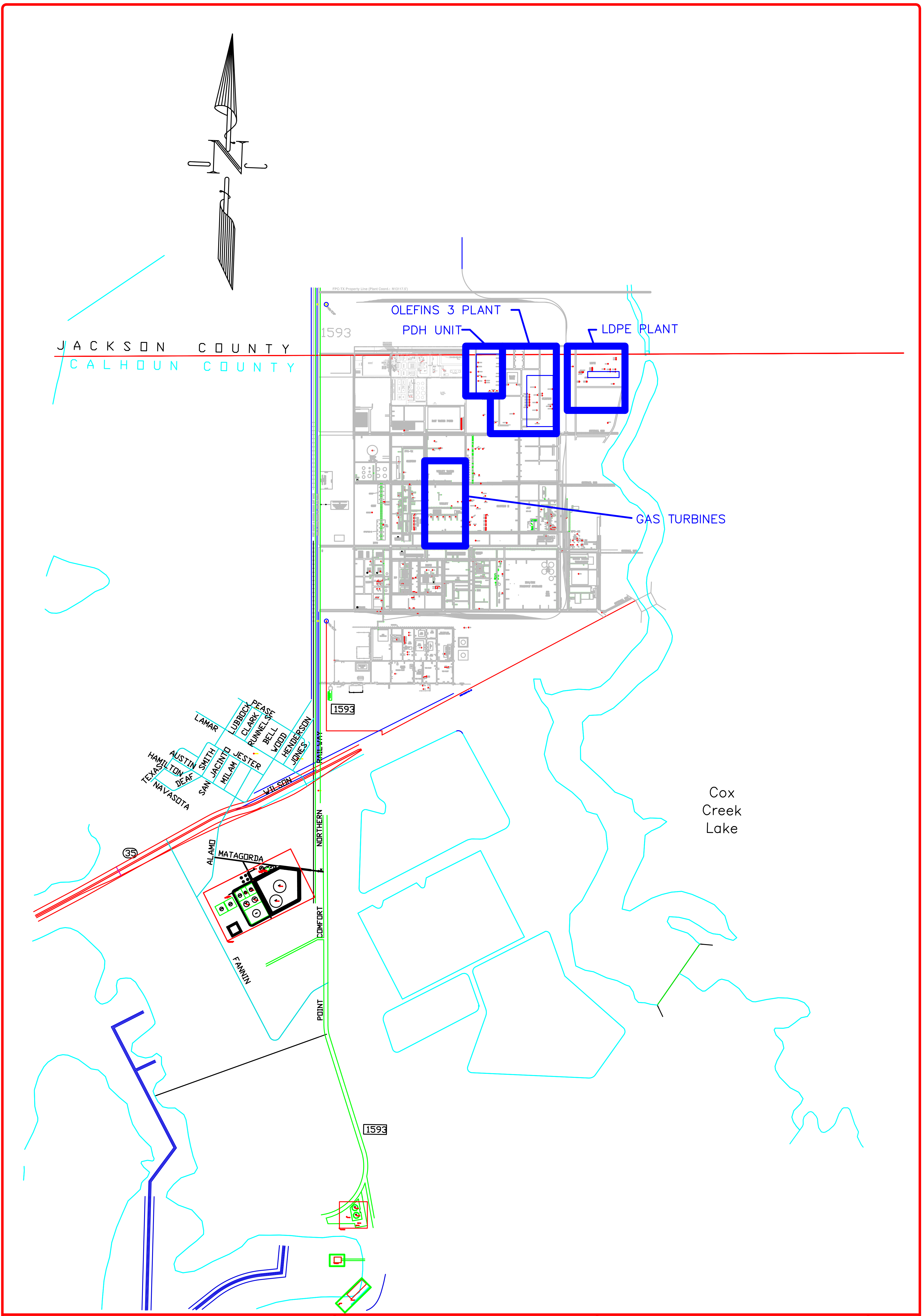
XIII. Signature

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: ______________________
Original Signature Required

Date: 11/27/12



Formosa Plastics®

DESCRIPTION: OVERALL VIEW
SHEET LAYOUT

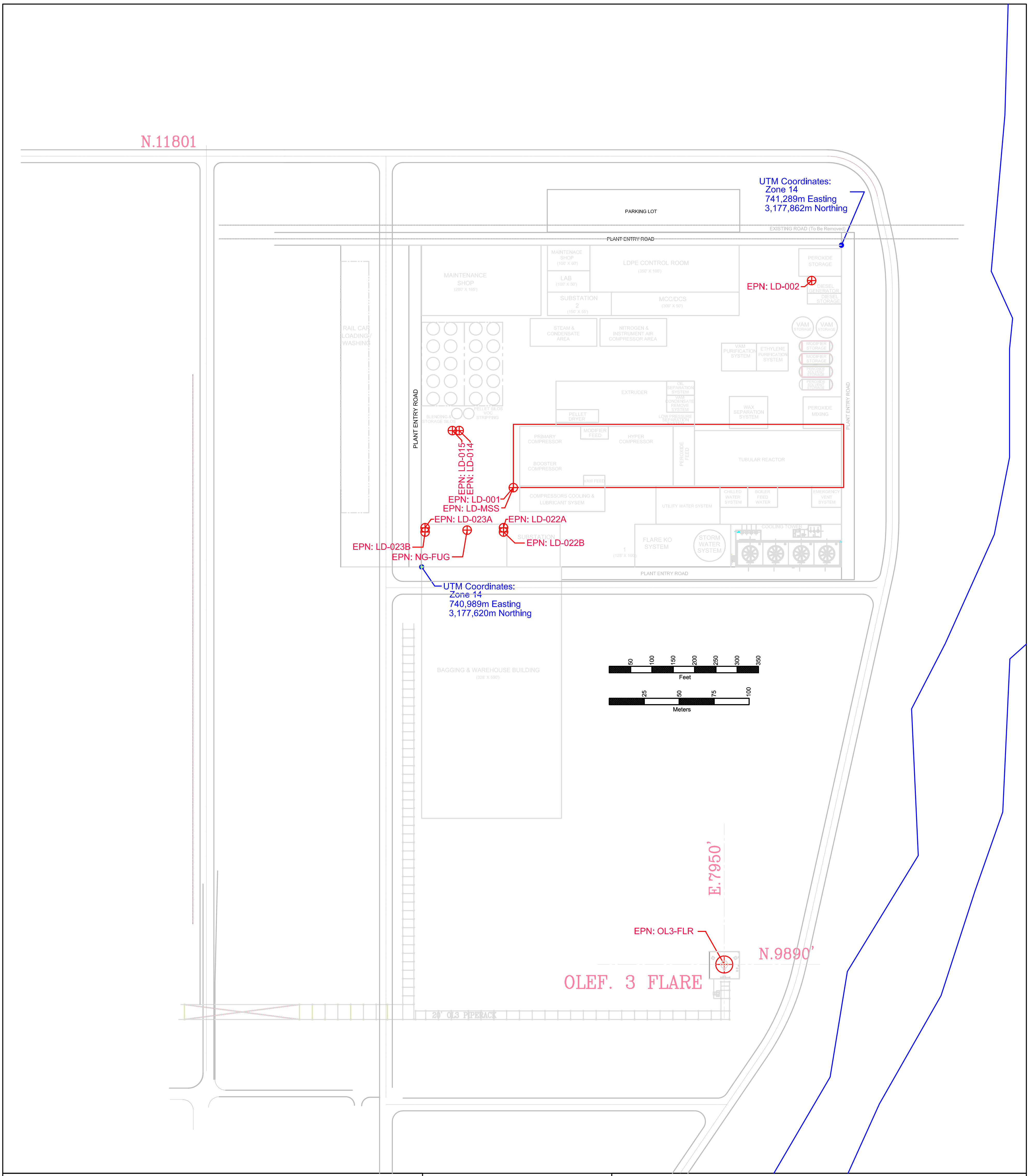
DRAWN BY : DWD	SCALE: 1" = 1000'	REFERENCE FILES
CHECKED BY: G.A.G.	DATE: 8/01/95	
APPROVED BY: G.A.G.	JOB NO. PC95-042	

PROJECT: Overall Plot Plan

CLIENT: FORMOSA PLASTICS CORP.

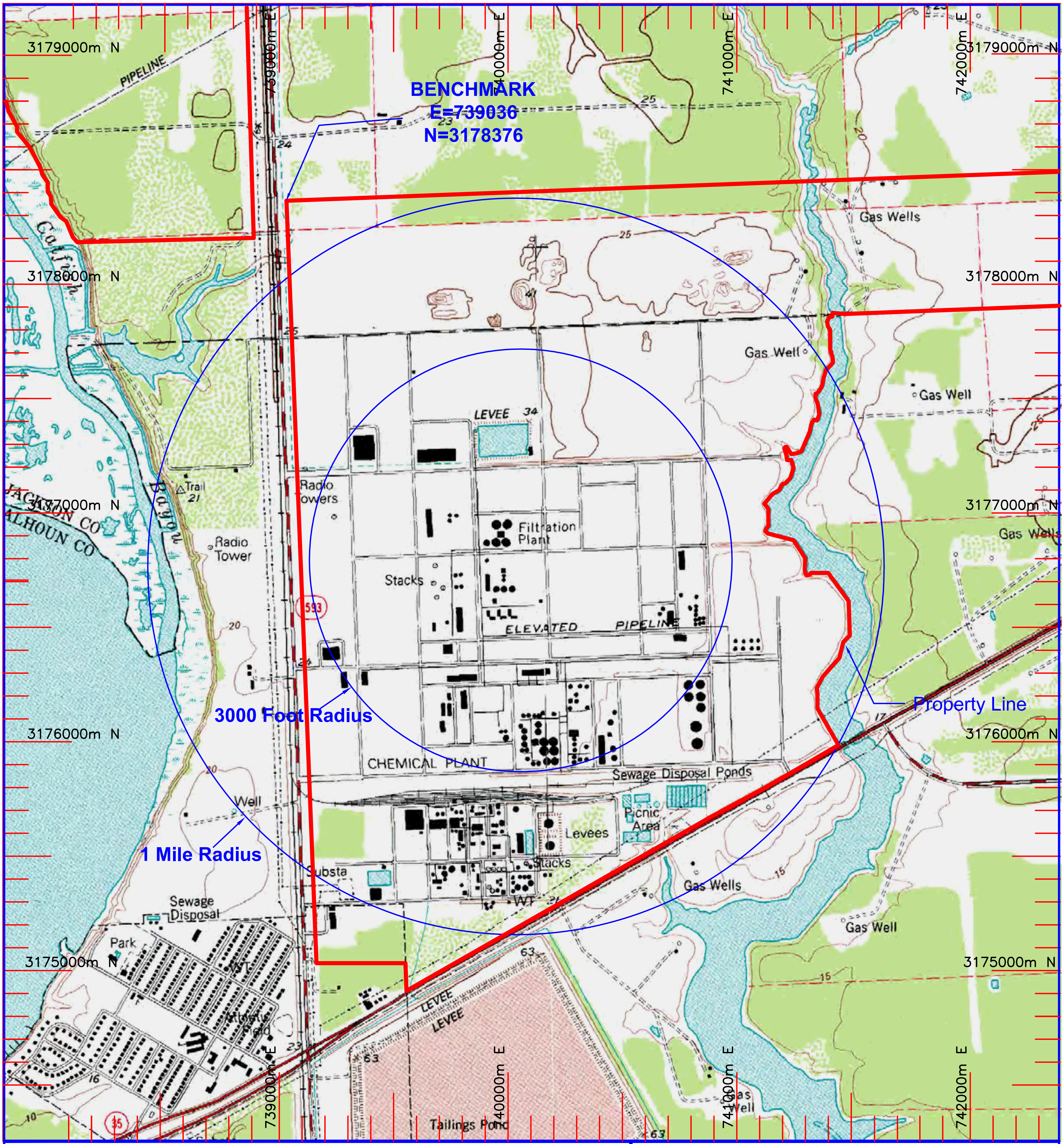
SHEET 1 OF 1

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



FORMOSA PLASTICS CORPORATION - TEXAS
Point Comfort, Texas

LDPE UNITS AND OL3 FLARE



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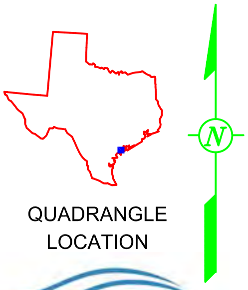
CONTOUR INTERVAL 5 FEET
COORDINATE DATUM: NAD83
U.S.G.S. 7.5 MINUTE SERIES (TOPOGRAPHIC)
POINT COMFORT, TEXAS QUADRANGLE 1995



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

In the proposed LDPE plant, the polymerization process will be accomplished with a high pressure tubular reactor process. The LDPE plant will have the capability of producing many different grades of LDPE products including products that use vinyl acetate as a co-monomer. The major systems in the LDPE plant are described below in detail. The following discussion refers to stream numbers listed on the process flow diagram, which is included at the end of this section.

Ethylene Feed System

Ethylene is the primary monomer in the polymerization reaction. Ethylene is received from neighboring Olefins plants by pipeline (Stream 1). The polymerization reaction takes place at high pressure; therefore, the ethylene feed stream must be compressed prior to entering the tubular reactor.

Compressor System

The compressor system includes primary and secondary compressors, a low pressure booster compressor, and an initiator compressor. Ethylene is typically received from battery limits (stream 1) at approximately 370 psig. The recycle ethylene (stream 19) from the low pressure recovery system is compressed by the low pressure booster compressor to combine with the fresh ethylene feed. The combined flow is then boosted to approximately 4,000 psig by the primary compressor. The high pressure recovery gas (stream 25) is mixed with the feed stream after primary compressor discharge. The combined flow is then boosted up to approximately 50,000 psig in the secondary compressor prior to reactor entry (stream 3). After compression additional reactants are added to stream 3 before entering the reactor as described below.

Peroxide feed System

An organic peroxide is used as initiator for the polymerization reaction. The peroxide (Stream 16) is received in cylinders and is stored in a refrigerated storage area. The storage refrigeration system is powered by the FPC TX centralized utility power system with backup provided by an emergency generator.

The peroxide must be mixed with a solvent prior to introduction to the process. Both peroxide and solvent are then transferred into a mix tank, the mixed peroxide/solvent stream (Stream 18) is transferred with metering pumps into the reactor feed stream upstream of the reactor preheater.

Vinyl Acetate Monomer Feed System

Vinyl Acetate (VA) may be used as co-monomer in the polymerization reaction depending on the product grade being produced. The VA is received by truck (Stream 13) and transferred into a storage tank. When making vinyl acetate co-monomer products, VA is pumped from the tank (Stream 15) into the reactor feed stream (ethylene) upstream of the secondary compressor.

Propionaldehyde Feed System

Propionaldehyde is used as moderator to control the rate of the polymerization reaction. Propionaldehyde is received in truck and transferred into a storage tank after which it is pumped, after the addition of propylene modifier (described below) through metering pumps (Stream 12) into the secondary ethylene compressor feed stream.

Propylene Feed System

Propylene is introduced into the reaction system as a modifier to produce certain grades of LDPE. When LDPE grades that require propylene are produced, then propylene is received from the neighboring Olefins plant by pipeline and mixed with the propionaldehyde moderator prior to metering it (stream 12) into the primary compressor discharge line (stream 2) to mix with the ethylene feed.

Reactor Polymerization System

The ethylene, peroxide, VA, propionaldehyde, and propylene mixture (depending on the LDPE product grade being produced) are fed to the tubular reactor to produce a polyethylene solution. The polymerization reaction occurs in the tubular reactor which consists of several reactor zones. Close control of process conditions, material feed rates, such as the monomer, co-monomer, initiator, moderator and modifiers discussed above are used to produce the various grades of LDPE resin desired.

High Pressure and Low Pressure Gas Recovery System

The reactor effluent, a solution of polyethylene and unreacted monomer, leaves the reactor, (Stream 4) before entering a high pressure separator (Stream 5). The high pressure separator separates unreacted monomer (Stream 24) from polyethylene product. A small amount of low molecular weight polymer (wax) leaves with the monomer gas stream after separation. The wax is considered a byproduct of the LDPE process and will be sold or transferred offsite for disposal.

After the high pressure separation described above, the molten polymer stream is routed into the low pressure separation system (Stream 6) to further separate the dissolved gas from polymer. The overhead gas stream from the separation knockout drum is further separated with a condenser into a recycle monomer stream (Stream 19) and a vinyl acetate stream (Stream 20). The gas/recycle monomer stream (Stream 19) is routed to the inlet of the low pressure booster compressor to be combined with fresh feed to the reactor. The molten polymer from the bottom of the low pressure separator (Stream 7) flows continuously into the melt extruder.

VA Recovery System

The unreacted vinyl acetate from the low pressure separator system polymer KO Drum (Stream 20) is sent to the vinyl acetate recovery column. From the column, the purified VA (Stream 22) is recycled back to the VA feed tank.

Additive Feed, Extrusion and Dryer System

This section consists of an additive system, melt extrusion system and equipment used to dry and convey pellets. The polymer from the low pressure separator (stream 7) is directly discharged into the melt extruder to mix with additives. The melted, mixed polymer is then forced through a die plate to make plastic “string”. This plastic “string” enters the enclosed cutter box, which is submerged in water, where it is cut underwater into smaller pieces by cutter knives, resulting in uniform plastic pellets. The pellets are instantly solidified and carried out of the cutter box by the circulating water to a centrifugal pellet dryer. The circulating water is removed from the pellets in the dryer and after being treated to adjust PH as described below, the water is recycled for reuse in the cutter box again. The pellets (Stream 8) are transferred into the degassing, blending and product silos as described below.

Degassing/Blending/Product Silos/ Rail Car Loading System

The final product pellets are sent to degassing silos (stream 8). The silos are equipped with an air purge system to strip VOCs. The purge air and the stripped VOCs (Stream 28) are routed to one of two regenerative thermal oxidizers (RTOs) for control (EPNs LD-022A/B, LD-023A/B), which are sources of GHG emissions from the combustion of pilot gas and waste gas. The product is then sent to blending and product silos (EPNs LD-014, LD-015, stream 9) for storage after which the final product is sent (stream 10) for bagging, bulk truck or rail car loading.

GHGs (methane and CO_2) can be formed in the polymerization reaction as an unfavorable side reaction. In order to maximize production of saleable product, the LDPE process design and control system inherently limits this side reaction; however, the side reaction kinetics cannot be completely eliminated. Residual non-polymerized materials, including unreacted feed material and the methane and CO_2 resulting from the peroxide side reaction described above, are expected to be removed from the polymer pellets in the degassing silos with the air purge stripping system described above. The blending silos are sources of GHG emissions as they may contain trace residual concentrations of GHGs that remain in the pellets after air stripping in the degassing silos.

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 LDPE plant 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 LDPE 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.

Reactor and Recovery System Design

The reaction conversion rate can vary depending on the type of LDPE process technology selected, which means that a significant quantity of unreacted ethylene will be present in the reactor effluent. FPC TX is proposing to design the LDPE plant with a technology that will maximize the feed conversion (yield) rate. In comparison, another LDPE process design option, with a lower conversion rate, would require significant additional ethylene recovery capacity as compared to FPC TX's proposed process design. To recover this additional quantity of unreacted ethylene, the separation system compressor would require additional electrical consumption. Thus, by selecting a process design that maximizes reaction conversion rate, less electrical energy is required to recover unreacted feed.

Electrical Equipment Selection

The LDPE plant 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 a lower load. Variable speed controllers are selected as the design specification for blowers, compressors and pumps to optimize electricity consumption.

3.2.2 Regenerative Thermal Oxidizers (RTOs)

The RTOs are operated to abate VOC emissions for emission sources downstream of the extruder (the pellet dryer and degassing silos). The RTOs emit GHGs as a result of waste gas and fuel gas combustion (FIN/EPNs: LD-022A/B, LD-023A/B). The RTOs will achieve 99% VOC destruction and removal efficiency as described in the non-GHG State PSD permit application. It should be noted that the waste gas routed to the RTO will not contain GHG species (e.g., methane). GHGs are emitted as a result of the combustion process, not from residual (uncontrolled) waste gas.

The RTOs are designed for redundant operation where waste gas can be routed to either RTO. Both RTOs may combust natural gas (“fuel gas”) simultaneously to keep the units at proper VOC destruction temperature.

3.2.3 Contributions to Olefins 3 Elevated Flare

Normal emission sources from the LDPE process upstream of and including the extruder are routed to the LDPE flare header. There are several flare header connections in the compression and reaction systems. The LDPE plant’s flare gas header is routed to the Olefins 3 elevated flare header where the waste gas is combusted along with waste gas from the Olefins 3 process. The contribution of GHG emissions from the combustion of the LDPE’s waste gas in the Olefins 3 elevated flare are addressed in this permit application (EPN: OL3-FLR).

3.2.4 Pellet Blending Silos

The pellet blending silos receive LDPE pellets from the degassing silos via pneumatic conveyance. This conveyance air is exhausted to the atmosphere through bagfilters (EPNs LD-014, LD-015, stream 9) and may contain small concentrations of GHGs (methane and CO2) that result from peroxide side reaction during the polymerization process. While, FPC TX does not expect GHG concentrations in the blending silo exhaust to be significant, this permit application provides a worst-case GHG emission calculation from these silos.

3.2.5 Emergency Generator Engine

The emergency generator engine (FIN/EPN: LD-002) combusts diesel fuel and is a source of GHG emissions. The emergency generator will be limited during non-emergency operating hours to testing and readiness checks as it is subject to NSPS Subpart IIII[3].

3.2.6 Planned Maintenance Startup and Shutdown (MSS)

As part of its normal operations, to assure that the plant continues to operate reliably and efficiently, planned maintenance is routinely performed. During these maintenance activities, equipment is planned to be opened to the atmosphere for MSS activities including but not limited to inspection, testing, maintenance, removal of accumulated solid material or flow restrictions, and repair. Again, the determination to open equipment is based on good engineering practices after careful review of the related design, operation, and/or maintenance information. Included in this determination are safety, employee health, and environmental considerations. This opening to atmosphere does not result in any GHG emissions. However, before opening to atmosphere, equipment must be depressured and purged to a VOC concentration of 10,000 ppmv or less. The gases purged from the equipment are routed to the flare for combustion resulting in GHG emissions (EPN: OL3-FLR).

3.2.7 Natural Gas Piping Fugitives

Natural gas is delivered to the site via pipeline. Natural gas will be metered and piped to the RTOs. Fugitive GHG emissions from the gas piping components associated with the RTOs will include emissions of methane (CH_4) and carbon dioxide (CO_2). Emissions from the natural gas piping are designated as EPN: NG-FUG.

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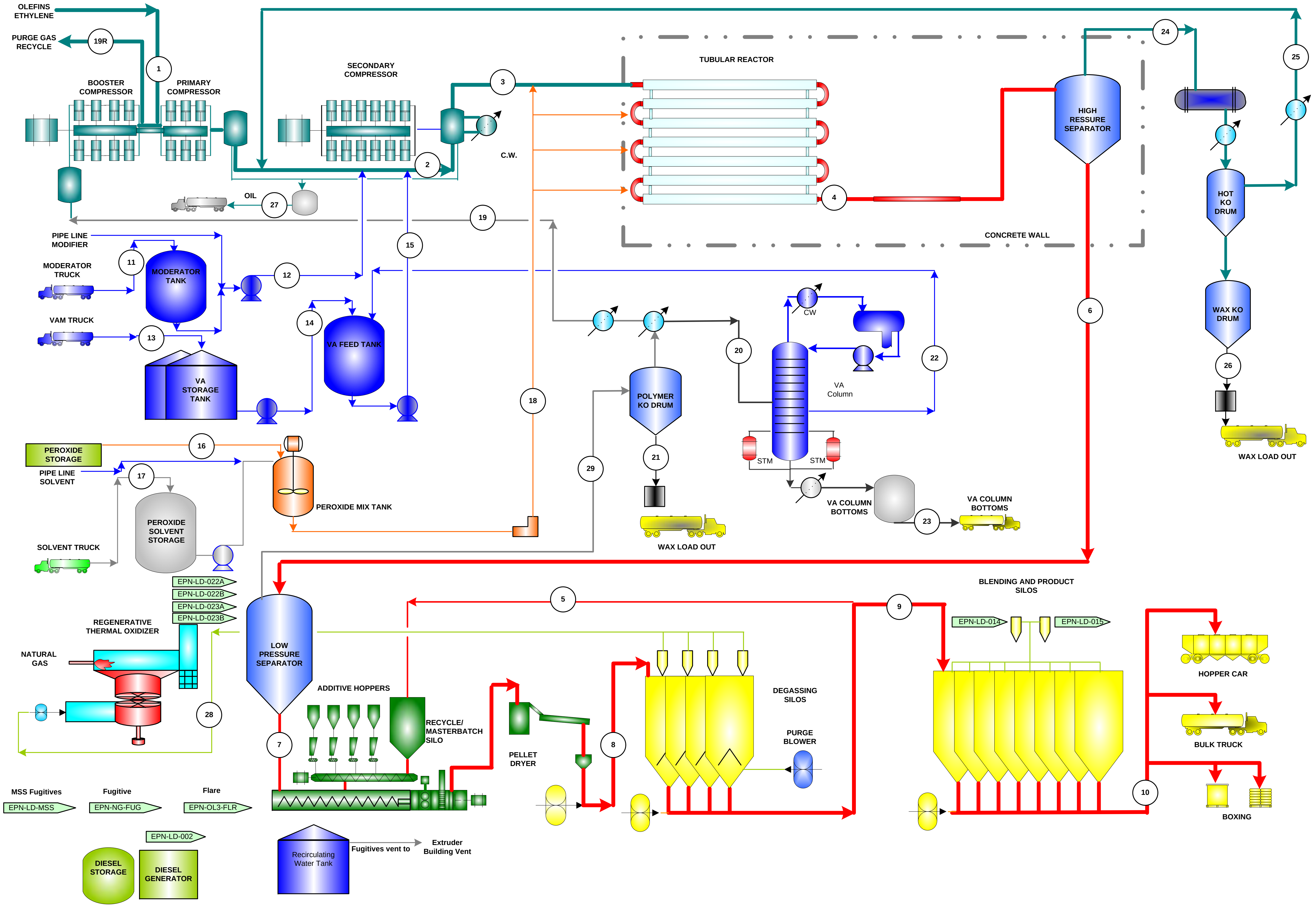
[3] 40 CFR 60, Subpart IIII


OLEFINS
ETHYLENE
PURGE GAS
RECYCLE
19R
1
BOOSTER
COMPRESSOR
PRIMARY
COMPRESSOR
SECONDARY
COMPRESSOR
3
2
C.W.
TUBULAR REACTOR
HIGH
RESSURE
SEPARATOR
24
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WAX KO
DRUM
26
WAX LOAD OUT
4
CONCRETE WALL
OIL
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PIPE LINE
MODIFIER
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VAM TRUCK
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VA FEED TANK
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POLYMER
KO DRUM
21
WAX LOAD OUT
VA COLUMN
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23
VA COLUMN
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PEROXIDE
STORAGE
16
PIPE LINE
SOLVENT
17
PEROXIDE MIX TANK
PEROXIDE
SOLVENT
STORAGE
SOLVENT TRUCK
29
EPN-LD-022A
EPN-LD-022B
EPN-LD-023A
EPN-LD-023B
REGENERATIVE
THERMAL OXIDIZER
NATURAL
GAS
28
LOW
PRESSURE
SEPARATOR
5
9
BLENDING AND PRODUCT
SILOS
EPN-LD-014
EPN-LD-015
ADDITIVE HOPPERS
RECYCLE/
MASTERBATCH
SILO
7
PELLET
DRYER
8
DEGASSING
SILOS
PURGE
BLOWER
HOPPER CAR
BULK TRUCK
10
BOXING
MSS Fugitives
EPN-LD-MSS
Fugitive
EPN-NG-FUG
Flare
EPN-OL3-FLR
EPN-LD-002
DIESEL
STORAGE
DIESEL
GENERATOR
Recirculating
Water Tank
Fugitives vent to
Extruder
Building Vent

4.0 GHG EMISSION CALCULATIONS

GHG Emission Calculations are performed based on the most representative emission calculation method provided in the Mandatory Greenhouse Reporting Rules in 40 CFR Part 98, as described below for each emission source. Emission calculations are included in Appendix A.

4.1 GHG EMISSIONS FROM NATURAL GAS COMBUSTION IN THE RTOS

GHG emission calculations for the natural gas-firing in the RTOs are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart C – Stationary Fuel Combustion Sources.[4]

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

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, as calculated by the RTO's burner design specifications (maximum rated capacity/heat input).

HHV = Default high heating value of the fuel, from Table C-1 of 40 CFR 98, mmBTU/scf

EF = Fuel-specific default CO_2 emission factor, from Table C-1 of 40 CFR 98, kg CO_2/mmBtu

1×10^{-3} = Conversion factor from kilograms 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]

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

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

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 WASTE GAS COMBUSTION IN RTOS AND FLARE

GHG emission calculations for the waste gas combustion in the RTOs and the Olefins 3 elevated flare are calculated in accordance with the equations and procedures in the Mandatory Greenhouse Reporting Rules, Subpart Y – Petroleum Refineries - Flares.[6]

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

Where:

CO_2 = Annual CO_2 mass emissions, metric tons/yr

Flare = Volume of waste gas combusted per year, standard cubic feet/yr, based on engineering estimates of waste gas volume (to the RTO or flare header)

CC = Annual average carbon content of waste gas (kg C per scf), based on engineering estimates of waste gas composition

MW = Annual average molecular weight of waste gas (kg/kg-mol), based on engineering estimates 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 VOC destruction efficiency (0.99 for RTO)

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

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[6] 40 CFR 98, Subpart Y – *Petroleum Refineries*

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 waste gas of 60 kg CO_2/MMBtu (HHV basis)

0.02/0.98 = Correction factor for flare minimum combustion efficiency (0.01/0.99 factor for RTO)

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 waste gas that is contributed by methane (kg CH4/kg C); default is 0.4.

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

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 waste gas of 60 kg CO_2/MMBtu (HHV basis)

4.3 GHG EMISSIONS FROM PELLET BLENDING SILO VENTS

GHG emissions from silo vents were calculated in accordance with the procedures in the Mandatory Greenhouse Reporting Rules, Subpart Y – for process vents[7].

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

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 the maximum design exhaust flow rate (i.e., blower capacity/rating)

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

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 FUEL OIL-FIRED EMERGENCY ENGINE

GHG emissions from the diesel-fired emergency engine was 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[8].

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

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

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[7] 40 CFR 98, Subpart Y – *Petroleum Refineries*

[8] 40 CFR 60, Subpart IIII

Default CH_4 emission factor (kg CH_4/mmBtu) = 3.0 E-03
Default N_2O emission factor (kg N_2O/mmBtu) = 6.0 E-04

4.5 GHG EMISSIONS FROM MSS ACTIVITIES

GHG emissions from waste gas flaring (products of combustion) are calculated using the same methodology described in Section 4.2. 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.

4.6 GHG EMISSIONS FROM NATURAL GAS FUGITIVES

GHG emission calculations for natural gas piping component fugitive emissions are based on emission factors from Table W-1A of the Mandatory Greenhouse Gas Reporting Rules.[9] 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 OL tail gas is variable, the concentrations of CH_4 and CO_2 from the typical natural gas analysis are used as a worst-case estimate. Although audio/visual/olfactory (AVO) inspections are being proposed as BACT for this source (see Section 6.6) 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.[10]

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

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

5.0 PREVENTION OF SIGNIFICANT DETERIORATION APPLICABILITY

Since the Point Comfort expansion project[11] emissions increase of GHG is greater than 75,000 ton/yr of CO_2e, PSD is triggered for GHG emissions. The emissions netting analysis includes all GHG emission sources from the 2012 Expansion Project and is documented on the attached TCEQ PSD netting tables: Table 1F and Table 2F found in Appendix B. Note that the project emission sources associated with the LDPE plant are new and, as such, there are no contemporaneous GHG emission changes associated with the project.

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 sources.

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[11] Includes emission sources from Olefins 3 plant, LDPE plant and gas 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.[12]

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.[13] 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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[12] 40 C.F.R. § 52.21(b)(12.)

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

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 LDPE plant 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 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.

6.2 BACT FOR REGENERATIVE THERMAL OXIDIZERS

6.2.1 Step 1: Identify All Available Control Technologies

6.2.1.1 RTO Selection and Energy Efficient Design and Operation

Regenerative thermal oxidizers are inherently designed with energy efficiency in mind and provide superior energy efficiency compared to a standard (non-regenerative) thermal oxidizer unit. RTOs are specifically designed to minimize the amount of fuel required to maintain the minimum firebox temperature. Specifically, the RTO firebox is lined with ceramic fiber refractory material to provide superior heat retention. RTOs are designed for high (more than 90%) thermal efficiency. By selecting an RTO instead of a non-regenerative thermal oxidizer, FPC TX estimates as much as 50% reduction in fuel gas combustion, or approximately 316,000 MMBTU/yr (for both RTOs) of energy savings as compared to a non-regenerative (traditional) oxidizer unit. This fuel gas savings equates to an avoidance of 9,200 tpy CO_2e GHG emissions[14].

The LDPE plant's RTOs will also be designed with a unique natural gas conservation (NGC) system which allows the RTO to maintain its combustion temperature without use of the primary burner. The primary burner may be switched off while natural gas is injected into one of the four corners of the system in the upper flow quadrant. The injected natural gas ignites as it rises up through the ceramic bed. This design feature results in the consumption of up to 20% less

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[14] Calculated using the GHG emission calculation methodology for this source based on selected design heat input of 36 MMBtu/hr (316,000 MMBtu/yr) of fuel gas for both RTOs..

natural gas (approximately 79,000 MMBTU/yr for both RTOs), thus avoiding GHG emissions upward of 4,600 tpy CO_2e[15].

The RTOs will also be designed to minimize the electrical power used to drive the combustion blower by installation of a variable speed blower and corresponding instrumentation and control systems. Compared to a traditional thermal oxidizer, FPC TX expects 40 kWh less electrical consumption. By selecting a variable speed blower and corresponding instrumentation and control systems, FPC TX estimates an energy savings resulting in avoidance of approximately 160 tpy CO_2e in upstream electrical generation emissions at FPC TX's utilities plant[16].

6.2.1.2 Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel gas, thus selection of natural gas as the RTO fuel will minimize emissions of GHGs from RTO fuel combustion.

6.2.2 Step 2: Eliminate Technically Infeasible Options

No technically infeasible 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.

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[15] Calculated using the GHG emission calculation methodology for this source, based on 36 MMBtu/hr (316,000 MMBtu/yr) of fuel gas heat input to both RTOs as selected design with NGC system.

[16] Calculated using combined cycle turbine emission rate of 0.913 lb CO_2/kW

6.2.5 Step 5: Select BACT

FPC TX will use natural gas as the RTO fuel gas and utilize energy efficient design and operation of the RTO, as described in Step 1 (above), to limit the amount of fuel gas required to maintain the minimum firebox temperature and achieve 99% destruction of VOCs (the primary function of the RTO). 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 RTO which takes into consideration the operation, variability and interaction of all these energy efficient features in combination. A holistic BACT limit considers the ultimate performance of the entire unit, rather than individual independent subsystem performance which 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 numeric energy efficiency-based BACT limit for RTO fuel gas (natural gas) of 18 MMBTU/hr (per RTO), based on a twelve month rolling average. To demonstrate compliance with this limit, FPC TX proposes to use fuel gas flow monitoring in conjunction with natural gas heating values to calculate the twelve month rolling average fuel gas heat input to the RTOs. This numeric BACT limit will provide ongoing demonstration that the RTOs achieve the represented energy efficiency by limiting heat input (fuel use) via operation of the natural gas conservation systems.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for RTOs and found no entries which address BACT for GHG emissions. In addition, FPC TX searched pending permit applications and issued GHG permits in other states and EPA regions for any proposed RTOs at chemical plants and found nothing. Although not listed in the RACT/BACT/LAER Clearinghouse, a review was completed of the GHG BACT analysis in other GHG permit applications submitted to EPA Region 6 that included an RTO. A discussion of FPC TX's proposed BACT as compared to those projects is provided below.

ExxonMobil Chemical – Mont Belvieu Plastics Plant

On May 21, 2012 ExxonMobil Chemical submitted a permit application to EPA Region 6 authorizing the construction of a new low-pressure polyethylene unit. The permit application included an RTO and proposed the following for BACT: natural gas as assist gas, good operating and maintenance practices and energy efficient design. The permit application also included a low-profile flare as a backup control device during periods of RTO outage.

FPC TX is proposing to construct a high-pressure LDPE plant, which features different equipment and operating parameters as compared to ExxonMobil's low-pressure process. Although these two process types differ significantly, FPC TX is including a comparison of the proposed GHG BACT for the RTOs to ExxonMobil's in this section.

ExxonMobil is proposing to use one RTO as a control device with a low-profile flare as backup during RTO outages. In contrast, the high-pressure process that is proposed by FPC TX requires routing of process vents from the front-end (reaction section) of the process to the elevated flare for control. Only those process vents in the back-end are proposed to be routed to the RTOs. For these vents, FPC TX is proposing to use two (redundant) RTOs for emission control. In doing so, 99% destruction of VOCs will be achieved (versus 98% in a flare) at all times.

FPC TX is proposing specific energy efficient RTO design options (e.g., natural gas conservation system) and a holistic, numeric energy efficiency-based BACT limit and monitoring methods as BACT for the RTOs. In addition, by selecting redundant RTOs (two), versus a combination of control device types (e.g., RTO and flare), the VOC destruction efficiency will be maximized for the waste streams routed to the RTOs.

Targa Gas Processing LLC – Longhorn Gas Plant

On February 17, 2012 Targa submitted a GHG permit application to EPA Region 6 requesting authorization of a new natural gas processing plant. This permit application included one RTO for which the applicant proposed the following BACT: use of natural gas as fuel gas, and proper RTO design, operation and maintenance. Targa also proposed a numeric BACT limit for total annual GHG emissions (12-month rolling average) and proposed monitoring fuel gas flow rate to demonstrate compliance.

FPC TX is also proposing fuel gas monitoring but is additionally proposing an energy efficiency-based numeric BACT limit which limits the fuel gas fired in the RTOs. In addition, by selecting redundant RTOs (two), the control device on-stream time and thus the overall VOC destruction efficiency will be maximized for the waste streams routed to the RTOs.

6.3 BACT FOR CONTRIBUTIONS TO ELEVATED FLARE

6.3.1 Step 1: Identify All Available Control Technologies

Proper operation of the elevated flare, consistent with 40 CFR 60.18, (addressed in the Olefins 3 GHG permit application) will ensure proper destruction of hydrocarbons, including methane. Operating the LDPE plant to minimize the amount of hydrocarbon waste gas routed to the flare will minimize the quantity of GHG emissions resulting from flaring of LDPE plant waste gas. It is estimated that proper operation of the LDPE plant (with the recycle and reuse described in the process description) is expected, based on the process design, to minimize waste gas routed to the flare by several orders of magnitude, which corresponds to a GHG emission reduction of approximately 4.3 million tons/yr CO_2e.[17]

6.3.2 Step 2: Eliminate Technically Infeasible Options

No technically infeasible options are being eliminated in this step.

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[17] Calculated using the calculation method described in the GHG emission calculation section of this application for this source

6.3.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated other than CCS, which is addressed in Section 6.1.

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

FPC TX will operate the LDPE plant to minimize the amount of waste gas generated and routed to the flare header. Since operational practices employed to minimize waste gas flaring are not independent of each other (but are interdependent) and represent an integrated waste gas minimization strategy, FPC TX is proposing a BACT limit which takes into consideration the operation, variability and interaction of each operational control in combination. A holistic BACT limit considers the ultimate performance of the entire LDPE plant (i.e., all contributions to Olefins 3 elevated flare), rather than individual independent subsystem performance which cannot necessary be controlled independent without affecting other parameters.

FPC TX proposes a numeric BACT emission limit for LDPE waste gas stream flaring of 3,704 tons/yr CO_2e, based on a rolling 12-month average. FPC TX will monitor the waste gas flow rate routed to the Olefins 3 elevated flare header to demonstrate compliance with this emission limit on a twelve month rolling average 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. In addition, FPC TX searched pending permit applications and issued GHG permits in other states and EPA regions for flares at chemical plants and found nothing. Although not listed in the RACT/BACT/LAER Clearinghouse, a review was completed of the GHG BACT analysis in other GHG permit applications submitted to EPA Region 6 which included flares. The only application which addressed flaring in the EPA Region 6 data base was the ExxonMobil Chemical – Mont Belvieu

Plastic Plant. A discussion of FPC TX's proposed BACT as compared to that project is provided below.

ExxonMobil Chemical – Mont Belvieu Plastics Plant

The permit application for a low-pressure process included a flare and proposed natural gas as the assist gas and good operating and maintenance practices as BACT.

FPC TX is proposing the construction of a high-pressure process, which requires those process vents in the upstream (e.g., reaction section) of the process to be routed to an elevated flare for safe control. FPC TX's proposed flare vent system design differs significantly from the one proposed by ExxonMobil. However, for the general purposes of relative comparison these systems are each discussed in this section.

In addition to the BACT options proposed by ExxonMobil for the low-pressure flare, FPC TX is proposing recycle and reuse of process vent gases rather than flaring all gases which reduces GHG emissions and a numeric BACT limit and monitoring for the LDPE plant's contributions to the Olefins 3 elevated flare.

6.4 BACT FOR PELLET BLENDING SILO VENTS

6.4.1 Step 1: Identify All Available Control Technologies

By operating the degassing silos and associated air purge stripping system, located upstream of the blending silos (described in the process description), FPC TX does not expect any measurable amount of GHG compounds to be emitted from the pellet blending silos (downstream of the stripping silos). However, FPC TX is including GHG emissions from the pellet blending silos as a worst-case. Operation of the pellet degassing silos to minimize the pellets' residual concentration of CO_2 and methane is the primary GHG control option available for this source.

6.4.2 Step 2: Eliminate Technically Infeasible Options

No BACT options are being eliminated in this step.

6.4.3 Step 3: Rank Remaining Control Technologies

No BACT options are being eliminated in this step.

6.4.4 Step 4: Evaluate Most Effective Controls and Document Results

No BACT options are being eliminated in this step.

6.4.5 Step 5: Select BACT

FPC TX is proposing to operate the upstream stripping silos and monitor the pellet blending silo exhaust stream heating value as BACT. Monitoring the heating value of the pellet blending silo will alert FPC TX operations in the case that insufficient stripping (upstream) is being achieved. The heating value measurement is a direct indicator of the presence of volatiles (including GHGs) in the blending silo exhaust stream. FPC TX is proposing an initial control point of 5 Btu/scf, based on a 3-hour average measurement. Exhaust stream heating value measurements at or above this value will trigger operations to increase the quantity of stripping air in the upstream stripping silos. To demonstrate ongoing compliance, FPC TX will retain records of the exhaust stream heating value and corresponding records of air purge stripping system operational adjustments (e.g., increasing stripping air flow rate) that are made when the measured heating value is equal to or greater than the control point.

FPC TX performed a search of the EPA's RACT/BACT/LAER Clearinghouse for polymer silos and found no entries which address BACT for GHG emissions. In addition, FPC TX searched pending permit applications and issued GHG permits in other states and EPA regions for silo vents at chemical plants and found nothing. 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, however no applicants had represented GHG emissions from silo vents.

6.5 BACT FOR EMERGENCY GENERATOR ENGINE

The proposed project will include installation of a new, high efficiency emergency generator. Use of these engines for purpose of maintenance checks and readiness testing will be limited to 100 hours per year each per the applicable New Source Performance Standard for Stationary Compression Ignition Internal Combustion Engines.[18] As such, the engines will be required to meet specific emission standards based on engine size, model year, and end use.

The use of engines with a low annual capacity factor and performance of annual routine maintenance (as prescribed by the NSPS) is BACT for GHG emissions.

6.6 BACT FOR NATURAL GAS AND FUEL GAS PIPING FUGITIVES

6.6.1 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 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.

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[18] *See* 40 CFR Part 60, Subpart IIII.

6.6.2 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), 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 LDPE unit.

6.6.3 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 accepted by EPA as an acceptable alternative to Method 21 instrument monitoring and leak detection effectiveness is expected to comparable. However, 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.

6.6.4 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.

6.6.5 Step 5: Select BACT

Please note the total GHG fugitive emissions are expected to be less than 0.5% of the total GHG emissions from the proposed LDPE plant. FPC- TX proposes to perform weekly AVO monitoring of piping components associated with the LDPE unit 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 all methane fugitive piping components.
- **BASF FINA - NAFTA Region Olefins Complex**
    - The final permit specifies 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.*[19]

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.*[20]

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

[20] *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.*[21]

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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[21] *Id.*

APPENDIX A

GHG EMISSION CALCULATIONS

Table A-1
Plantwide GHG Emission Summary
Formosa Plastic Corporation, Texas
LDPE Plant
November 2012

Name	EPN	GHG Mass Emissions ton/yr	CO_2e ton/yr
RTO 1 [1]	LD-022A/B	31,550	32,306
RTO 2 [1]	LD-023A/B		
Waste Gas to OL3 Elevated Flare [2]	OL3-FLR	21,933	22,216
Pellet Blending Silo 1	LD-014	4,818	17,810
Pellet Blending Silo 2	LD-015	4,818	17,810
Emergency Engine	LD-002	207	229
Natural Gas Piping Fugitives	NG-FUG	20.9	425
LDPE Plant MSS Vessel Opening	LD-MSS	0.01	0.08
	Total [3] =	**63,347**	**90,796**

Notes:

[1] Waste gas combustion can occur in either RTO. Unit-specific maximum emission rates shown here assume that 100% of annual waste gas is routed to each RTO.

[2] Includes MSS emissions from LDPE plant MSS degassing to Olefins 3 elevated flare.

[3] Total annual emissions account for 100% of waste gas combustion in either RTO unit. That is, RTO unit-specific annual emission rates are not additive.

Table A-2
GHG Emission Calculations - Natural Gas Combustion
Formosa Plastic Corporation, Texas
LDPE Plant
November 2012

GHG Emissions Contribution From Natural Gas Combustion:

							Emissions per Unit			
Source Type	Average Heat Input/unit (MMBtu/hr)	Number of units	Annual Operation 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)
RTOs	18.0	2	8,760	157,680	CO_2	53.02	8,360.2	1	8,360.2	9,217.1
					CH_4	1.0E-03	0.16	21	3.3	3.7
					N_2O	1.0E-04	0.02	310	4.9	5.4
						Totals	**8,360**		**8,368**	**9,226**

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 C Equation C-1

CH_4 and N_2O Emissions from 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 Calculations, CO_2:

GHG Mass Emissions = 0.001 x 157680 (MMBtu/yr) x 53.02 (kg/MMBtu) = 8360.2 (metric ton/yr)

CO2e Emissions (from CO2) = 8360.2 (metric ton/yr) x 1 (GWP factor) = 8360.2 (metric ton/yr)

Table A-3

GHG Emission Calculations - RTO Waste Gas Combustion

Formosa Plastic Corporation, Texas

LDPE Plant

November 2012

RTO Waste Gas Data:

Variable	Value	Units	Reference
Carbon content (annual avg)	0.0031	kg C/kg	Formosa design data
Molecular Weight (annual avg)	29.1	kg/kmol	Formosa design data

GHG Emissions from RTO Waste Gas Combustion:

Source Type	Annual Avg Waste 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)
RTOs 1 & 2	5.26E+10	CO_2	2.02E+04	1	2.02E+04	2.23E+04
		CH_4	3.07E+01	21	6.45E+02	7.11E+02
		N_2O	2.02E-01	310	6.27E+01	6.91E+01
		Totals	**2.03E+04**		**2.09E+04**	**2.31E+04**

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

CH_4 emissions based on 40 CFR Part 98, Subpart Y Equation Y-4

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

Sample Calculations, CO_2:

GHG Mass Emissions = 44/12 x 5.26E+10 (scf/yr) x 0.0031 (kg C/kg) x (29.1 (kg/mol) /
849.5 scf/kg-mole @ std cond.) x 0.001 x 0.98
= 2.02E+04 (metric ton/yr)

CO2e Emissions (from CO2) = 2.02E+04 (metric ton/yr) x 1 = 2.02E+04 (metric ton/yr)

Table A-4

GHG Emission Calculations - Elevated Flare Contributions (Olefins 3 Elevated Flare)

Formosa Plastic Corporation, Texas

LDPE Plant

November 2012

Flare Gas Data:

Variable	Value	Units	Reference
Carbon content (annual avg)	0.80	kg C/kg	Formosa design data
Molecular Weight (annual avg)	31.9	kg/kmol	Formosa design data

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	2.63E+07	CO_2	2.83E+03	1	2.83E+03	3.12E+03
		CH_4	8.53E+00	21	1.79E+02	1.98E+02
		N_2O	2.83E-02	310	8.76E+00	9.66E+00
		Totals	**2.84E+03**		**3.01E+03**	**3.32E+03**

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

CH_4 emissions based on 40 CFR Part 98, Subpart Y Equation Y-4

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

Sample Calculations, CO_2:

GHG Mass Emissions = (44/12) x 2.63E+07 (scf/yr) x 0.8 (kg C/kg) x
(31.91 (kg/mol) / 849.5 (scf/kg-mole @ std cond.)) x 0.001 x 0.98
= 2.83E+03 (metric ton/yr)

CO2e Emissions (from CO2) = 2.83E+03 (metric ton/yr) x 1 = 2.83E+03 (metric ton/yr)

Table A-5
GHG Emission Calculations - Pellet Blending Silo Vents
Formosa Plastic Corporation, Texas
LDPE Plant
November 2012

Pellet Blending Silo Vent Data:

Variable	Value	Units	Reference
Volumetric flow rate (annual avg), each silo	1,190,400	scf/hr	design specification
CO_2 Concentration	0.70	mol %	design specification
CH_4 Concentration	0.30	mol %	design specification
Maximum vent operating schedule	8,760	hours/yr	design specification

Constants:

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

CO_2 Emissions from Pellet Blending Silo Vents:

Source Type	Pollutant	GHG Mass Emissions[1] (metric ton/yr)	Global Warming Potential[2]	CO_2e (metric ton/yr)	CO_2e (tpy)
Pellet Blending Silo 1	CO_2	3,781	1	3,781	4,168
	CH_4	589	21	12,374	13,642
Pellet Blending Silo 2	CO_2	3,781	1	3,781	4,168
	CH_4	589	21	12,374	13,642
	Total =	**8,740**		**32,309**	**35,620**

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 Calculations, CO_2:

GHG Mass Emissions = 1190400 (scf/hr) x (0.7 mol % / 100) x 8760 (hours/yr) x (44 kg/kgmol / 849.5 scf/kg-mol)
x 0.001 metric ton/kg = 3781 (metric ton/yr)

CO2e Emissions (from CO2) = 3781 (metric ton/yr) x 1 = 3781 (metric ton/yr)

Table A-6
GHG Emission Calculations - Emergency Engine
Formosa Plastic Corporation, Texas
LDPE Plant
November 2012

Diesel Engine Specifications:

Variable	Value	Units	Reference
Ann.Operating Schedule	100	hours/year	NSPS IIII Limitation
Power Rating	400	hp	design specification
Brake Specific Fuel Consumption	7,000	Btu/hp-hr	AP-42 average fuel consumption for diesel engine

GHG Emissions Contribution From Diesel Combustion In Emergency Engines:

EPN	Annual Heat Input (MMBtu/yr)	Pollutant	Emission Factor (kg/MMBtu)[1]	GHG Mass Emissions (metric ton/yr)	Global Warming Potential[2]	CO_2e (metric ton/yr)	CO_2e (tpy)
LD-002	2,800	CO_2	73.96	207.1	1	207.1	228.3
		CH_4	3.0E-03	0.0084	21	0.2	0.2
		N_2O	6.0E-04	0.0017	310	0.5	0.6
				207.10		**207.8**	**229.1**

Calculation Procedure (From 40 CFR 98 Subpart C, Equation C-1)

Annual Emission Rate = Annual Heat Input (Fuel) X Emission Factor (EF) X 0.001 (metric tons/kg)

Notes:

1. *GHG factors based on Tables C-1 and C-2 of 40 CFR 98 Mandatory Greenhouse Gas Reporting for diesel fuel (distillate fuel oil no. 2).*
2. *Global Warming Potential factors based on Table A-1 of 40 CFR 98 Mandatory Greenhouse Gas Reporting.*

Sample Calculations, CO_2:

GHG Mass Emissions = 2800 (MMBtu/yr) x 73.96 (kg/MMBtu) x 0.001 ton/kg = 207.1 (metric ton/yr)

CO2e Emissions (from CO2) = 207.1 (metric ton/yr) x 1 = 207.1 (metric ton/yr)

Table A-7
GHG Emission Calculations - Fugitive Component Emissions
Formosa Plastic Corporation, Texas
LDPE Plant
November 2012

GHG Emissions Contribution From Fugitive 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)	Methane (tpy)	Total (tpy)
NG-FUG	Valves	Gas/Vapor	600	0.121	1.20%	96.6%	0.436	12.80	
	Flanges	Gas/Vapor	2400	0.017			0.245	7.19	
	Relief Valves	Gas/Vapor	5	0.193			5.80E-03	1.70E-01	
	Sampling Connections	Gas/Vapor	10	0.031			1.86E-03	5.46E-02	
	Compressors	Gas/Vapor	3	0.002			3.60E-05	1.06E-03	
GHG Mass-Based Emissions							0.689	20.2	***20.9***
Global Warming Potential[2]							1	21	
CO_2e Emissions							0.69	424.5	***425.2***

Notes:

1. Emission factors from Table W-1A 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.

Example calculation:

600 valves	0.121 scf gas	0.012 scf CO2	lbmol	44.01 lb CO_2	8760 hr	ton	0.44	ton/yr
	hr * valve	scf gas	385 scf	lbmol	yr	2000 lb		

Table A-8

GHG MSS Emission Calculations
Formosa Plastics Corporation, Texas
2012 Expansion Project: LDPE Plant

November 2012

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: LD-MSS	Piping	0.0000	0.0002	0.0002
	Tanks	0.0000	0.0000	0.0000
	Large Equipment	0.0003	0.0023	0.0026
	Small Equipment Components	0.0012	0.0095	0.0104
	Misc.	0.0080	0.0562	0.0619
	Subtotal	**0.01**	**0.07**	**0.08**
Flare Emissions EPN: OL3-FLR	Piping	56	56	62
	Tanks	349	350	386
	Large Equipment	7,262	7,297	8,043
	Small Equipment Components	7,108	7,141	7,872
	Misc.	2,283	2,294	2,529
	Subtotal	**17,058**	**17,139**	**18,892**
	Total	**17,058**	**17,139**	**18,892**

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)						3,034,027	3,990,283
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)						3,034,027	3,990,283
FNSR applicable? (yes or no)						Yes	Yes

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	99,732		99,732		99,732
2	OL3-FUR2	OL3-FUR2		0.00	0.00	99,732		99,732		99,732
3	OL3-FUR3	OL3-FUR3		0.00	0.00	99,732		99,732		99,732
4	OL3-FUR4	OL3-FUR4		0.00	0.00	99,732		99,732		99,732
5	OL3-FUR5	OL3-FUR5		0.00	0.00	99,732		99,732		99,732
6	OL3-FUR6	OL3-FUR6		0.00	0.00	99,732		99,732		99,732
7	OL3-FUR7	OL3-FUR7		0.00	0.00	99,732		99,732		99,732
8	OL3-FUR8	OL3-FUR8		0.00	0.00	99,732		99,732		99,732
9	OL3-FUR9	OL3-FUR9		0.00	0.00	99,732		99,732		99,732
10	OL3-BOIL1	OL3-BOIL1		0.00	0.00	164,532		164,532		164,532
11	OL3-BOIL2	OL3-BOIL2		0.00	0.00	164,532		164,532		164,532
12	OL3-BOIL3	OL3-BOIL3		0.00	0.00	164,532		164,532		164,532
13	OL3-BOIL4	OL3-BOIL4		0.00	0.00	164,532		164,532		164,532
14	PDH-REAC1	PDH-REAC1		0.00	0.00	61,185		61,185		61,185
15	PDH-REAC2	PDH-REAC2		0.00	0.00	61,185		61,185		61,185
16	PDH-REAC3	PDH-REAC3		0.00	0.00	61,185		61,185		61,185
17	PDH-REAC4	PDH-REAC4		0.00	0.00	61,185		61,185		61,185
18	OL3-FUG	OL3-FUG		0.00	0.00	3.91		3.91		3.91
19	PDH-FUG	PDH-FUG		0.00	0.00	0.94		0.94		0.94

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

					A	**B**				
Affected or Modified Facilities(2)	**FIN**	**EPN**	**Permit No.**	**Actual Emissions(3)**	**Baseline Emissions(4)**	**Proposed Emissions(5)**	**Projected Actual Emissions**	**Difference (B - A) (6)**	**Correction (7)**	**Project Increase(8)**
20	OL3-FLR	OL3-FLR		0.00	0.00	118,050	see Note 1	118,050		118,050
21	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	985.6		985.6		985.6
22	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	985.6		985.6		985.6
23	OL3-DK1	OL3-DK1		0.00	0.00	211.6		211.6		211.6
24	OL3-DK2	OL3-DK2		0.00	0.00					
25	OL3-MAPD	OL3-MAPD		0.00	0.00	20.9		20.9		20.9
26	PDH-MSSVO	PDH-MSSVO		0.00	0.00	2.55		2.55		2.55
27	OL3-MSSVO	OL3-MSSVO		0.00	0.00	1.70		1.70		1.70
28	OL3-GEN	OL3-GEN		0.00	0.00	447		447		447
29	PDH-GEN	PDH-GEN		0.00	0.00	447		447		447
30	N6460FA/B	1087	19168	2.33	2.33	2.82	see Note 2	0.49		0.49
LDPE Plant Sources										
31	LD-022A/B	LD-022A/B		0.00	0.00	31,550		31,550		31,550
32	LD-023A/B	LD-023A/B		0.00	0.00					
33	OL3-FLR	OL3-FLR		0.00	0.00	21,933	see Note 1	21,933		21,933
34	LD-014	LD-014		0.00	0.00	4,818		4,818		4,818
35	LD-015	LD-015		0.00	0.00	4,818		4,818		4,818
36	LD-002	LD-002		0.00	0.00	207.1		207.1		207.1
37	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
38	LD-MSS	LD-MSS		0.00	0.00	0.01		0.01		0.01
Combined Cycle Turbine Sources										
39	7K	7K		0.00	0.00	524,520		524,520		524,520
40	7L	7L		0.00	0.00	524,520		524,520		524,520
41	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	1.24		1.24		1.24
42	NG-FUG	NG-FUG		0.00	0.00	20.9		20.9		20.9
43	SF6-FUG	SF6-FUG		0.00	0.00	<0.01		0.01		0.01
Notes:							**Total =**			**3,034,027**

[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

					A	B				
Affected or Modified Facilities(2)	**FIN**	**EPN**	**Permit No.**	**Actual Emissions(3)**	**Baseline Emissions(4)**	**Proposed Emissions(5)**	**Projected Actual Emissions**	**Difference (B - A) (6)**	**Correction (7)**	**Project Increase(8)**
Olefins 3 Plant Sources										
1	OL3-FUR1	OL3-FUR1		0.00	0.00	99,865		99,865		99,865
2	OL3-FUR2	OL3-FUR2		0.00	0.00	99,865		99,865		99,865
3	OL3-FUR3	OL3-FUR3		0.00	0.00	99,865		99,865		99,865
4	OL3-FUR4	OL3-FUR4		0.00	0.00	99,865		99,865		99,865
5	OL3-FUR5	OL3-FUR5		0.00	0.00	99,865		99,865		99,865
6	OL3-FUR6	OL3-FUR6		0.00	0.00	99,865		99,865		99,865
7	OL3-FUR7	OL3-FUR7		0.00	0.00	99,865		99,865		99,865
8	OL3-FUR8	OL3-FUR8		0.00	0.00	99,865		99,865		99,865
9	OL3-FUR9	OL3-FUR9		0.00	0.00	99,865		99,865		99,865
10	OL3-BOIL1	OL3-BOIL1		0.00	0.00	164,754		164,754		164,754
11	OL3-BOIL2	OL3-BOIL2		0.00	0.00	164,754		164,754		164,754
12	OL3-BOIL3	OL3-BOIL3		0.00	0.00	164,754		164,754		164,754
13	OL3-BOIL4	OL3-BOIL4		0.00	0.00	164,754		164,754		164,754
14	PDH-REAC1	PDH-REAC1		0.00	0.00	289,840		289,840		289,840
15	PDH-REAC2	PDH-REAC2		0.00	0.00	289,840		289,840		289,840
16	PDH-REAC3	PDH-REAC3		0.00	0.00	289,840		289,840		289,840
17	PDH-REAC4	PDH-REAC4		0.00	0.00	289,840		289,840		289,840
18	OL3-FUG	OL3-FUG		0.00	0.00	77.97		77.97		77.97
19	PDH-FUG	PDH-FUG		0.00	0.00	15.76		15.76		15.76
20	OL3-FLR	OL3-FLR		0.00	0.00	128,455	See Note 1	128,455		128,455
21	OL3-LPFLR1	OL3-LPFLR1		0.00	0.00	1,040.7		1,040.7		1,040.7
22	OL3-LPFLR2	OL3-LPFLR2		0.00	0.00	1,040.7		1,040.7		1,040.7
23	OL3-DK1	OL3-DK1		0.00	0.00	211.6		211.6		211.6
24	OL3-DK2	OL3-DK2		0.00	0.00					
25	OL3-MAPD	OL3-MAPD		0.00	0.00	20.90		20.90		20.90
26	PDH-MSSVO	PDH-MSSVO		0.00	0.00	3.81		3.81		3.81
27	OL3-MSSVO	OL3-MSSVO		0.00	0.00	35.1		35.1		35.1
28	OL3-GEN	OL3-GEN		0.00	0.00	448.5		448.5		448.5
29	PDH-GEN	PDH-GEN		0.00	0.00	448.5		448.5		448.5
30	N6460FA/B	1087		2.72	2.72	3.29	See Note 2	0.57		0.57

Pollutant(1):	CO2e	**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**								
LDPE Plant Sources										
31	LD-022A/B	LD-022A/B		0.00	0.00	32,306		32,306		32,306
32	LD-023A/B	LD-023A/B		0.00	0.00					
33	OL3-FLR	OL3-FLR		0.00	0.00	22,216	See Note 1	22,216		22,216
34	LD-014	LD-014		0.00	0.00	17,810		17,810		17,810
35	LD-015	LD-015		0.00	0.00	17,810		17,810		17,810
36	LD-002	LD-002		0.00	0.00	229.1		229.1		229.1
37	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
38	LD-MSS	LD-MSS		0.00	0.00	0.08		0.08		0.08
Combined Cycle Turbine Sources										
39	7K	7K		0.00	0.00	525,024		525,024		525,024
40	7L	7L		0.00	0.00	525,024		525,024		525,024
41	7K-NGVENT, 7L-NGVENT	7K-NGVENT, 7L-NGVENT		0.00	0.00	25.1		25.1		25.1
42	NG-FUG	NG-FUG		0.00	0.00	425.2		425.2		425.2
43	SF6-FUG	SF6-FUG		0.00	0.00	29.6		29.6		29.6
	Summary of Contemporaneous Changes						**Total**			**3,990,283**

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):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- PDH regeneration vents (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):

- 9 cracking furnaces (Olefins Expansion)
- 4 PDH Reactors (Olefins Expansion)
- 4 steam boilers (Olefins Expansion)
- PDH regeneration vent (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)

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

- cost of obtaining rights of way for construction of a pipeline

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]	2,913,739		$128,525,043
Maximum Cost	$103.42 / ton of CO_2 avoided [3]	2,913,739		$301,336,173
Average Cost	$73.76 / ton of CO_2 avoided [4]	2,913,739		$214,930,608
CO_2 Transport System				
Minimum Cost	$0.91 / ton of CO_2 transported per 100 km [3]	2,913,739	150	$3,964,950
Maximum Cost	$2.72 / ton of CO_2 transported per 100 km [3]	2,913,739	150	$11,894,849
Average Cost	$1.81 / ton of CO_2 transported per 100 km [4]	2,913,739	150	$7,929,899
CO_2 Storage System				
Minimum Cost	$0.51 / ton of CO_2 stored [3, 6]	2,913,739		$1,480,248
Maximum Cost	$18.14 / ton of CO_2 stored [3, 6]	2,913,739		$52,865,995
Average Cost	$9.33 / ton of CO_2 stored [4]	2,913,739		$27,173,122
Total Cost for CO_2 Capture, Transport, and Storage Systems				
Minimum Cost	$45.98 / ton of CO_2 removed	2,913,739		$133,970,240
Maximum Cost	$125.65 / ton of CO_2 removed	2,913,739		$366,097,017
Average Cost	$85.81 / ton of CO_2 removed [4]	2,913,739		$250,033,629

[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.

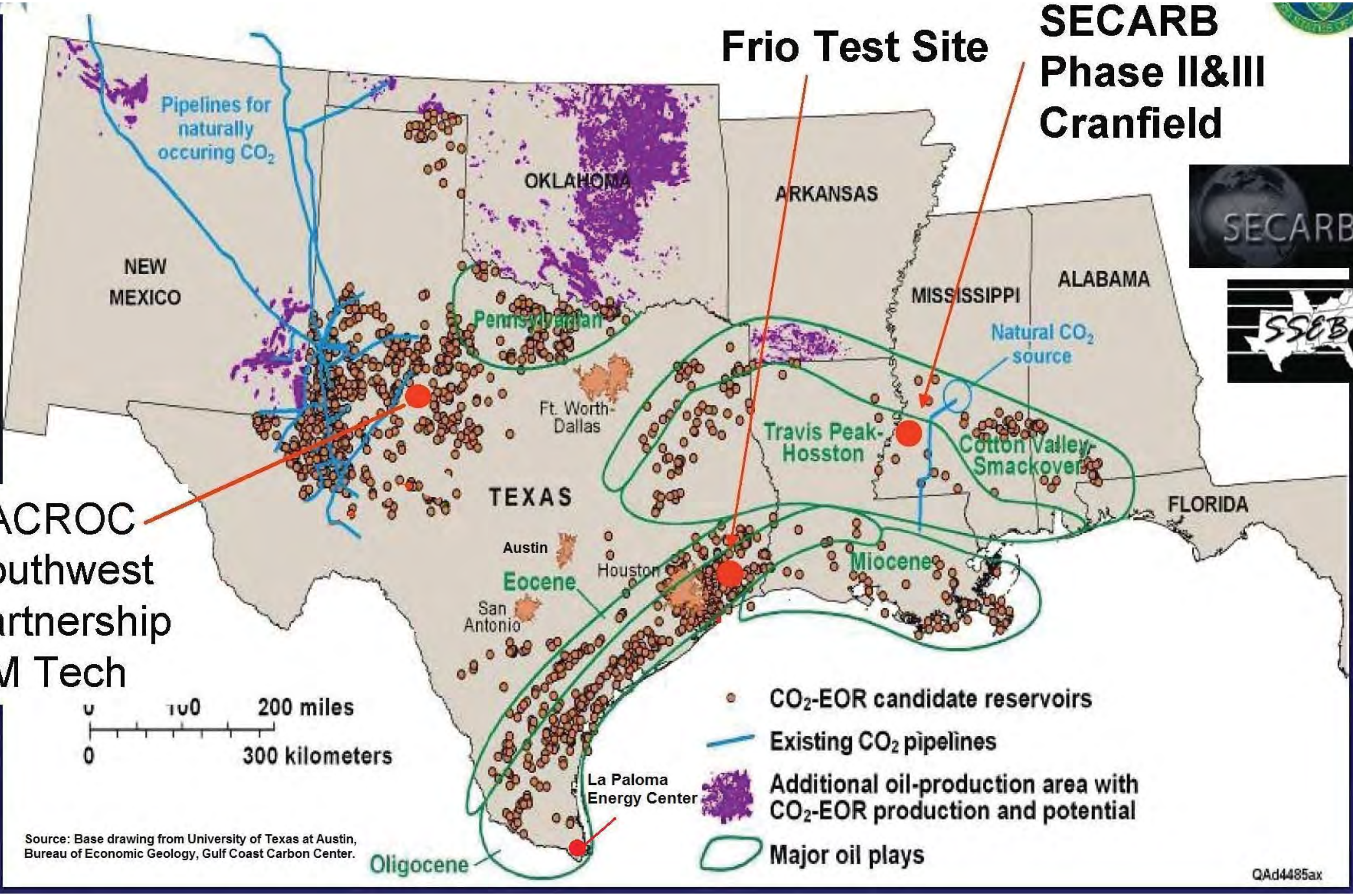
[5] The length of the pipeline was assumed to be the distance to the closest potential geologic storage site, as identified by the University of Texas at Austin, Bureau of Economic Geology, Gulf Coast Carbon Center, available at: http://www.beg.utexas.edu/gccc/graphics/Basemap_state_lands_fp_lg.jpg (last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