Permit:	146425	**Project:**	268176	**Company:**	GCGV ASSET HOLDING LLC	**RN:**	RN109753731
Type:	CONSTRUCT	**Type:**	INITIAL	**Constr. Date:**	2nd Q 2018	**Pub. Notice:**	NAPD

P1 SB1756 —

Industry	Olefins Plant	**SIC Code**	2869	**NAICS Code**	325199	**Consultant**	Sage
Reviewed by:	TSH	**Pending at site:**	268178(PSDTX1518)[TLDRCHEM (04/20/2017, 1 days)] 268179(GHGPSDTX170)[TLDRCHEM (04/20/2017, 1 days)]				

Description:

This project is a joint venture (ExxonMobil and SABIC) to construct a grassroots olefin and derivatives production complex. Derivatives include two polyethylene units and a glycol unit. Emission sources include cracking furnaces, boilers, process vents, cooling towers, wastewater treatment (using ToxChem), storage tanks (using Tanks ESP), loading, engines, thermal oxidizers, elevated flare, ground flare, fugitives, and MSS. (Claim of AVO control credit for H2SO4 may not be appropriate unless concentration is high.)

This project is a joint venture (ExxonMobil and SABIC) to construct a grassroots olefin and derivatives production complex. Derivatives include two polyethylene units and a glycol unit. Emission sources include cracking furnaces, boilers, process vents, cooling towers, wastewater

, storage tanks, loading, thermal oxidizer, elevated flare, ground flare, engines, fugitives, and MSS. Check control credit for H2SO4 fugitive; must have high concentration to claim AVO control credit.

Linked to project 268178 on permit PSDTX1518 (INITIAL):

Linked to project 268179 on permit GHGPSDTX170 (INITIAL):

Backlog date:	1/28/2018	***CHEMICAL SITE REVIEWS ON TOM'S J: DRIVE (J:\everyone\APD Staff\T Lawshae\Site Reviews)***	Notify legislators per SB709.

Proj. Attribute	**Description**
County	Site is located in SAN PATRICIO county.
CC	Site is located in the Corpus Christi-Victoria AQCR.
major-source	The permit action is at a site subject to Title V.

Proj. Attribute	Description
110(a)	A permit or amendment is required under 30 TAC §116.110(a) before the applicant can commence non-exempt construction or modification.
NAPD	Permit amendment requires public notice under 30 TAC §39.402.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Protecting Texas by Reducing and Preventing Pollution

April 20, 2017

MR WILLIAM H CHEEK
PRESIDENT
GCGV ASSET HOLDING LLC
10375 RICHMOND AVE STE 1800
HOUSTON TX 77042-4188

Re: Expedited Permitting Program Acceptance
Permit Numbers: 146425, PSDTX1518, and GHGPSDTX170
GCGV Asset Holding LLC
Gulf Coast Growth Ventures Project
Gregory, San Patricio County
Regulated Entity Number: RN109753731
Customer Reference Number: CN605357219

Dear Mr. Cheek:

Thank you for submitting the Expedited Permitting Request form and surcharge to participate in the Texas Commission on Environmental Quality (TCEQ) Expedited Permitting Program. After reviewing the submittal, the project has been accepted into.the Expedited Program pursuant to Title 30 Texas Administrative Code, Chapter 101, Subchapter J.

Please be aware that an expedited review requires a high-quality application that provides all of the information, data, and analysis needed to allow a complete review, and an applicant that is exceptionally responsive to requests for clarification and additional data. I am sure that you will provide a high level of commitment, and I can assure you that the TCEQ will match your commitment efforts.

Review the guidance for expedited permitting on our website at www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/epp-in-impl-guide-external-6258.pdf for information on the program.

Re: Permit Numbers: 146425, PSDTX1518, and GHGPSDTX170

If you have any questions related to your expedited permit balance, you may call Mr. Michael Partee at (512) 239-3312.

Sincerely,

Michael Wilson, P.E., Director
Air Permits Division
Office of Air
Texas Commission on Environmental Quality

Enclosure

cc: Air Section Manager, Region 14 - Corpus Christi

Project Number: 268176, 268178, 268179

Stephanie Ross

From:	Michael Partee
Sent:	Thursday, April 20, 2017 3:42 PM
Cc:	TAMMY.HEADRICK@EXXONMOBIL.COM; RFCAIR14
Subject:	Expedited Permitting Request
Attachments:	Expedited Permitting Request Project 268176, 268178, 268179.pdf

Mr. Cheek,

Thank you for your interest in the Texas Commission on Environmental Quality (TCEQ) Expedited Permitting Program. In response to your expedited permitting request, please review the attached letter.

Form APD-EXP Expedited Permitting Request

I. Contact Information	
Company or Other Legal Customer Name: **GCGV Asset Holding LLC**	
Customer Reference Number (CN): **TBD**	
Regulated Entity Number (RN): **TBD**	
Company Official or Technical Contact Name: **Tammy Headrick**	
Phone Number: **832-625-4775**	
Email: **tammy.headrick@exxonmobil.com**	
II. Project Information	
Facility Type: **Olefins, Derivatives, & Utilities**	
Permit Number: **TBD**	
Project Number: **TBD**	
III. Economic Justification	
The purpose of the application associated with this request to expedite will benefit the economy of this state or an area of this state.	☒ YES ☐ NO
IV. Delinquent Fees and Penalties	
Applications will not be expedited if any delinquent fees and/or penalties are owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.	
V. 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. As the applicant, I commit to fulfilling all expectations of the expedited permitting program and application requirements promptly. Failure to meet any expectation or requirement may cause my application to be removed from the expedited permitting program and possibly voided at the discretion of the TCEQ Executive Director. 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: **William H Cheek**	
Signature: WH Chl	
Date: 4/12/17	

APR 19 2017
APIRT

Texas Commission on Environmental Quality
Form APD-APS Air Permitting Surcharge Payment

I. Contact Information	
Company or Other Legal Customer Name: GCGV Asset Holding LLC	
Customer Reference Number (CN): TBD	
Regulated Entity Number (RN): TBD	
Company Official or Technical Contact Information: (☐ Mr. ☒ Mrs. ☐ Ms. ☐ Other:______)	
Name: Tammy Headrick	
Title: Environmental Advisor, GCGV Asset Holding	
Mailing Address: 10375 Richmond Avenue, Suite 1800	
City: Houston	
State: TX	
ZIP Code: 77042	
Telephone Number: 832-625-4775	
E-mail Address: tammy.headrick@exxonmobil.com	
II. Project Information	
Facility Name: Gulf Coast Growth Venture (GCGV)	
Permit Number: TBD	
Project Number: TBD	
III. Surcharge Payment	
Project Type: Federal NSR permit	
Fee Amount: $ 20,000	
Check, Money Order, Transaction Number, and/or ePay Voucher Number: *(below)*	
Paid Online:	☐ YES ☒ NO
Company Name on Check: Sage ATC Environmental Consulting LLC	

Form APD-EXP Expedited Permitting Request

I. Contact Information	
Company or Other Legal Customer Name: **GCGV Asset Holding LLC**	
Customer Reference Number (CN): **TBD**	
Regulated Entity Number (RN): **TBD**	
Company Official or Technical Contact Name: **Tammy Headrick**	
Phone Number: **832-625-4775**	
Email: **tammy.headrick@exxonmobil.com**	
II. Project Information	
Facility Type: **Olefins, Derivatives, & Utilities**	
Permit Number: **TBD**	
Project Number: **TBD**	
III. Economic Justification	
The purpose of the application associated with this request to expedite will benefit the economy of this state or an area of this state.	☒ YES ☐ NO
IV. Delinquent Fees and Penalties	
Applications will not be expedited if any delinquent fees and/or penalties are owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.	
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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. As the applicant, I commit to fulfilling all expectations of the expedited permitting program and application requirements promptly. Failure to meet any expectation or requirement may cause my application to be removed from the expedited permitting program and possibly voided at the discretion of the TCEQ Executive Director. 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: **William H Cheek**	
Signature: WH Cheek	
Date: 4/12/17	

Texas Commission on Environmental Quality
Form APD-APS Air Permitting Surcharge Payment

I. Contact Information	
Company or Other Legal Customer Name: GCGV Asset Holding LLC	
Customer Reference Number (CN): TBD	
Regulated Entity Number (RN): TBD	
Company Official or Technical Contact Information: (☐ Mr. ☒ Mrs. ☐ Ms. ☐ Other:______)	
Name: Tammy Headrick	
Title: Environmental Advisor, GCGV Asset Holding	
Mailing Address: 10375 Richmond Avenue, Suite 1800	
City: Houston	
State: TX	
ZIP Code: 77042	
Telephone Number: 832-625-4775	
E-mail Address: tammy.headrick@exxonmobil.com	
II. Project Information	
Facility Name: Gulf Coast Growth Venture (GCGV)	
Permit Number: TBD	
Project Number: TBD	
III. Surcharge Payment	
Project Type: Federal NSR permit	
Fee Amount: $ 20,000	
Check, Money Order, Transaction Number, and/or ePay Voucher Number: *(below)*	
Paid Online:	☐ YES ☒ NO
Company Name on Check: Sage ATC Environmental Consulting LLC	

Return to Sharenet

04/25/2017 --------------NSR IMS - PROJECT RECORD --

PROJECT#: 268179 PERMIT#: GHGPSDTX170 STATUS: PENDING DISP CODE: __________
RECEIVED: 04/19/2017 PROJTYPE: INITIAL AUTHTYPE: GHGPSD ISSUED DT: __________
RENEWAL:
PROJECT ADMIN NAME: GULF COAST GROWTH VENTURES PROJECT
PROJECT TECH NAME: GULF COAST GROWTH VENTURES PROJECT

Assigned Team: CHEMICAL SECTION

STAFF ASSIGNED TO PROJECT:

ROSS , STEPHANIE	- REVIEWR1_2 -	AP INITIAL REVIEW
TEAM LEADER , CHEM	- REVIEW ENG -	CHEMICAL SECTION

CUSTOMER INFORMATION (OWNER/OPERATOR DATA)
ISSUED TO: GCGV ASSET HOLDING LLC
COMPANY NAME: GCGV Asset Holding LLC
CUSTOMER REFERENCE NUMBER: **CN605357219**

REGULATED ENTITY/SITE INFORMATION
REGULATED ENTITY NUMBER: **RN109753731** ACCOUNT:
PERMIT NAME: GULF COAST GROWTH VENTURES PROJECT

REGULATED ENTITY LOCATION: SOUTH OF HIGHWAY 181 AND WEST OF FM RD 2986
REGION 14 - CORPUS CHRISTI NEAR CITY: GREGORY COUNTY: SAN PATRICIO

CONTACT DATA

CONTACT NAME: MR WILLIAM H CHEEK CONTACT ROLE: RESPONSIBLE OFFICIAL
JOB TITLE: PRESIDENT ORGANIZATION: GCGV ASSET HOLDING LLC
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0

CONTACT NAME: MRS TAMMY HEADRICK CONTACT ROLE: TECHNICAL CONTACT
JOB TITLE: ENVIRONMENTAL ADVISOR GCGV ASSET HOLDING ORGANIZATION: EXXONMOBIL CHEMICAL COMPANY
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0
EMAIL:TAMMY.HEADRICK@EXXONMOBIL.COM

PROJECT NOTES:

04/20/2017 SOS/DFC/NO APWL
04/25/2017 SR DOC 583017, PN DOC 583018

PERMIT NOTES:

FEE:

Reference	Fee Receipt Number	Amount	Fee Receipt Date	Fee Payment Type
2435	M725870	75000.00	04/20/2017	CHECK

PUBLIC NOTICE:

Public Hearing Req Number	Public Meeting Req Number	Comment Count	Alternative Languages
0	0	0	SPANISH

TRACKING ELEMENTS:

TE Name	Start Date	Complete Date
APIRT RECEIVED PROJECT (DATE)	04/19/2017	
ENHANCED ADMINISTRATIVE OR APPLICATIONS REVIEW (EAR)	04/20/2017	04/20/2017
EXPEDITED PERMITTING	04/20/2017	
PUBLIC NOTICE DRAFT SENT TO COMPANY (DATE)	04/24/2017	
APIRT TRANSFERRED PROJECT TO TECHNICAL STAFF (DATE)	04/25/2017	
COMPANY APPROVED DRAFT PUBLIC NOTICE (DATE)	04/25/2017	
LEGISLATORS NOTIFIED OF APPLICATION RECEIVED (DATE)	04/25/2017	
PROJECT DECLARED ADMIN COMPLETE (DATE)	04/25/2017	
SITE REVIEW RFC SENT TO REGION (DATE)	04/25/2017	
1ST NOTICE OCC COMPLETE (DATE)		
2ND NOTICE OCC COMPLETE (DATE)		
2ND PUBLIC NOTICE FINALIZED AND SENT (DATE)		
CENTRAL REGISTRY UPDATED		
COMPLIANCE HISTORY REVIEW COMPLETED (DATE)		
DEFICIENCY CYCLE		
EMISSIONS MODELING CYCLE DONE BY APPLICANT		
EMISSIONS MODELING CYCLE DONE BY TCEQ		
FINAL PACKAGE REWORK CYCLE		
FINAL PACKAGE TO SECTION MANAGER FOR REVIEW (DATE)		
FINAL PACKAGE TO TEAM LEADER OR SUPERVISOR FOR REVIEW (DATE)		
LEGISLATORS NOTIFIED OF DRAFT PERMIT		
MODELING AUDIT CYCLE		
POSTED TO EXECUTIVE DIRECTOR'S AGENDA (DATE)		
PROJECT RECEIVED BY ENGINEER (DATE)		
PROJECT RECEIVED BY TECHNICAL STAFF FROM APIRT (DATE)		
PUBLIC NOTICE COMMENT PERIOD (NSR 1ST NOTICE)		
PUBLIC NOTICE COMMENT PERIOD (TITLE V OR NSR #2)		
RBLC ENTRY CYCLE		
TOXICOLOGY RFC CYCLE		
WORKING DRAFT PERMIT REVIEW CYCLE		
WPO FINAL PACKAGE CYCLE		

PROJECT ATTRIBUTES:

Attributes	Value
ECO DEV PROJECT	
SB1756	FULL

PROJECT LINKS

Link Id	Link Type	Program Code
146425	PERMIT	AIRNSR
PSDTX1518	PERMIT	AIRNSR
268176	PROJECT	AIRNSR
268178	PROJECT	AIRNSR

Return to Sharenet

04/25/2017 --------------NSR IMS - PROJECT RECORD --

PROJECT#: 268178 PERMIT#: PSDTX1518 STATUS: PENDING DISP CODE: __________
RECEIVED: 04/19/2017 PROJTYPE: INITIAL AUTHTYPE: PSD ISSUED DT: __________
RENEWAL:
PROJECT ADMIN NAME: GULF COAST GROWTH VENTURES PROJECT
PROJECT TECH NAME: GULF COAST GROWTH VENTURES PROJECT

Assigned Team: CHEMICAL SECTION

STAFF ASSIGNED TO PROJECT:

ROSS , STEPHANIE	- REVIEWR1_2 -	AP INITIAL REVIEW
TEAM LEADER , CHEM	- REVIEW ENG -	CHEMICAL SECTION

CUSTOMER INFORMATION (OWNER/OPERATOR DATA)
ISSUED TO: GCGV ASSET HOLDING LLC
COMPANY NAME: GCGV Asset Holding LLC
CUSTOMER REFERENCE NUMBER: **CN605357219**

REGULATED ENTITY/SITE INFORMATION
REGULATED ENTITY NUMBER: **RN109753731** ACCOUNT:
PERMIT NAME: GULF COAST GROWTH VENTURES PROJECT

REGULATED ENTITY LOCATION: SOUTH OF HIGHWAY 181 AND WEST OF FM RD 2986
REGION 14 - CORPUS CHRISTI NEAR CITY: GREGORY COUNTY: SAN PATRICIO

CONTACT DATA

CONTACT NAME: MR WILLIAM H CHEEK CONTACT ROLE: RESPONSIBLE OFFICIAL
JOB TITLE: PRESIDENT ORGANIZATION: GCGV ASSET HOLDING LLC
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0

CONTACT NAME: MRS TAMMY HEADRICK CONTACT ROLE: TECHNICAL CONTACT
JOB TITLE: ENVIRONMENTAL ADVISOR GCGV ASSET HOLDING ORGANIZATION: EXXONMOBIL CHEMICAL COMPANY
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0
EMAIL:TAMMY.HEADRICK@EXXONMOBIL.COM

PROJECT NOTES:

04/20/2017 SOS/DFC/NO APWL
04/25/2017 SR DOC 583017, PN DOC 583018

PERMIT NOTES:

PUBLIC NOTICE:

Public Hearing Req Number	Public Meeting Req Number	Comment Count	Alternative Languages
0	0	0	SPANISH

TRACKING ELEMENTS:

TE Name	Start Date	Complete Date
APIRT RECEIVED PROJECT (DATE)	04/19/2017	
ENHANCED ADMINISTRATIVE OR APPLICATIONS REVIEW (EAR)	04/20/2017	04/20/2017
EXPEDITED PERMITTING	04/20/2017	
PUBLIC NOTICE DRAFT SENT TO COMPANY (DATE)	04/24/2017	
APIRT TRANSFERRED PROJECT TO TECHNICAL STAFF (DATE)	04/25/2017	
COMPANY APPROVED DRAFT PUBLIC NOTICE (DATE)	04/25/2017	
LEGISLATORS NOTIFIED OF APPLICATION RECEIVED (DATE)	04/25/2017	
PROJECT DECLARED ADMIN COMPLETE (DATE)	04/25/2017	
SITE REVIEW RFC SENT TO REGION (DATE)	04/25/2017	
1ST NOTICE OCC COMPLETE (DATE)		
2ND NOTICE OCC COMPLETE (DATE)		
2ND PUBLIC NOTICE FINALIZED AND SENT (DATE)		
CENTRAL REGISTRY UPDATED		
COMPLIANCE HISTORY REVIEW COMPLETED (DATE)		
DEFICIENCY CYCLE		
DRAFT PERMIT RFC SENT TO REGION (DATE)		
EMISSIONS MODELING CYCLE DONE BY APPLICANT		
EMISSIONS MODELING CYCLE DONE BY TCEQ		
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LEGISLATORS NOTIFIED OF DRAFT PERMIT		
MODELING AUDIT CYCLE		
POSTED TO EXECUTIVE DIRECTOR'S AGENDA (DATE)		
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PROJECT RECEIVED BY TECHNICAL STAFF FROM APIRT (DATE)		
PUBLIC NOTICE COMMENT PERIOD (NSR 1ST NOTICE)		
PUBLIC NOTICE COMMENT PERIOD (TITLE V OR NSR #2)		
RBLC ENTRY CYCLE		
TOXICOLOGY RFC CYCLE		
WORKING DRAFT PERMIT REVIEW CYCLE		
WPO FINAL PACKAGE CYCLE		

PROJECT ATTRIBUTES:

Attributes	Value
ECO DEV PROJECT	
SB1756	FULL

PROJECT LINKS

Link Id	Link Type	Program Code
146425	PERMIT	AIRNSR
GHGPSDTX170	PERMIT	AIRNSR
268176	PROJECT	AIRNSR
268179	PROJECT	AIRNSR

Return to Sharenet

04/25/2017 --------------NSR IMS - PROJECT RECORD ---

PROJECT#: 268176 PERMIT#: 146425 STATUS: PENDING DISP CODE: ________
RECEIVED: 04/19/2017 PROJTYPE: INITIAL AUTHTYPE: CONSTRUCT ISSUED DT: ________
RENEWAL:
PROJECT ADMIN NAME: GULF COAST GROWTH VENTURES PROJECT
PROJECT TECH NAME: GULF COAST GROWTH VENTURES PROJECT

Assigned Team: CHEMICAL SECTION

STAFF ASSIGNED TO PROJECT:

ROSS , STEPHANIE	- REVIEWR1_2 -	AP INITIAL REVIEW
TEAM LEADER , CHEM	- REVIEW ENG -	CHEMICAL SECTION

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COMPANY NAME: GCGV Asset Holding LLC
CUSTOMER REFERENCE NUMBER: **CN605357219**

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REGULATED ENTITY LOCATION: SOUTH OF HIGHWAY 181 AND WEST OF FM RD 2986
REGION 14 - CORPUS CHRISTI NEAR CITY: GREGORY COUNTY: SAN PATRICIO

CONTACT DATA

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JOB TITLE: PRESIDENT ORGANIZATION: GCGV ASSET HOLDING LLC
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0

CONTACT NAME: MRS TAMMY HEADRICK CONTACT ROLE: TECHNICAL CONTACT
JOB TITLE: ENVIRONMENTAL ADVISOR GCGV ASSET HOLDING ORGANIZATION: EXXONMOBIL CHEMICAL COMPANY
MAILING ADDRESS: 10375 RICHMOND AVE STE 1800, HOUSTON, TX, 77042-4188
PHONE: (832) 625-4775 Ext: 0
EMAIL:TAMMY.HEADRICK@EXXONMOBIL.COM

PROJECT NOTES:

04/20/2017 SOS/DFC/NO APWL
04/25/2017 SR DOC 583017, PN DOC 583018

PERMIT NOTES:

PUBLIC NOTICE:

Public Hearing Req Number	Public Meeting Req Number	Comment Count	Alternative Languages
0	0	0	SPANISH

TRACKING ELEMENTS:

TE Name	Start Date	Complete Date
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CENTRAL REGISTRY UPDATED		
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EMISSIONS MODELING CYCLE DONE BY TCEQ		
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LEGISLATORS NOTIFIED OF DRAFT PERMIT		
MODELING AUDIT CYCLE		
POSTED TO EXECUTIVE DIRECTOR'S AGENDA (DATE)		
PROJECT RECEIVED BY ENGINEER (DATE)		
PROJECT RECEIVED BY TECHNICAL STAFF FROM APIRT (DATE)		
PUBLIC NOTICE COMMENT PERIOD (NSR 1ST NOTICE)		
PUBLIC NOTICE COMMENT PERIOD (TITLE V OR NSR #2)		
TOXICOLOGY RFC CYCLE		
WORKING DRAFT PERMIT REVIEW CYCLE		
WPO FINAL PACKAGE CYCLE		

PROJECT ATTRIBUTES:

Attributes	Value
ECO DEV PROJECT	
SB1756	FULL

PROJECT LINKS

Link Id	Link Type	Program Code
GHGPSDTX170	PERMIT	AIRNSR
PSDTX1518	PERMIT	AIRNSR
268178	PROJECT	AIRNSR
268179	PROJECT	AIRNSR

Stephanie Ross

From:	Stephanie Ross
Sent:	Tuesday, April 25, 2017 1:28 PM
To:	OCC-NSR; R6AirPermitsTX@epa.gov
Cc:	RFCAIR14; TAMMY.HEADRICK@EXXONMOBIL.COM; THOMAS.WAUHOB@SAGEENVIRONMENTAL.COM
Subject:	Permit Application, GCGV Asset Holding LLC, 146425, 268176
Attachments:	268176.docx

Please see Public Notice attached.

Stephanie Ross

From:	Stephanie Ross
Sent:	Tuesday, April 25, 2017 1:20 PM
To:	RFCAIR14
Subject:	Site Review/Request for Comments for Project Number 268176
Attachments:	RFC-268176.docx

PLEASE DO NOT RESPOND TO THE PERSON SENDING THIS EMAIL.

This is a request for comments. Please submit comments to the individual and within the specified time frame as identified in the attached file.

Stephanie Ross

From:	Thomas Wauhob <thomas.wauhob@sageenvironmental.com>
Sent:	Tuesday, April 25, 2017 11:22 AM
To:	Stephanie Ross
Cc:	Headrick, Tammy; Jennifer Geran
Subject:	TCEQ Public Notice DRAFT - Air Permits 146425, PSDTX1518, and GHGPSDTX170
Attachments:	268176_DRAFT_cmt.docx

Greetings Stephanie, I am a consultant helping Tammy Headrick with the application referenced above. I have reviewed the draft notice and am attaching comments. Please call me at 832-392-8735 if you have any questions.

Thank you

Thomas Wauhob NSR permitting, Title V, Compliance Systems
SAGE ATC ENVIRONMENTAL CONSULTING
Friendly Service, No Surprises
N. Austin office
715 Discovery BLVD., #301
Cedar Park, TX 78613
O: 512-258-8500;1110
F: 512-258-7522
C: 832-392-8735

SAGEENVIRONMENTAL.COM

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

EXAMPLE A

NOTICE OF RECEIPT OF APPLICATION AND INTENT TO OBTAIN AIR PERMIT

PROPOSED AIR QUALITY PERMIT NUMBERS 146425,
PSDTX1518 AND GHGPSDTX170

APPLICATION GCGV Asset Holding LLC, has applied to the Texas Commission on Environmental Quality (TCEQ) for issuance of State Air Quality Permit Number 146425, issuance of Prevention of Significant Deterioration (PSD) Air Quality Permit Number PSDTX1518, and issuance of Greenhouse Gas (GHG) Prevention of Significant Deterioration (PSD) Air Quality Permit Number GHGPSDTX170, which would authorize construction of the Gulf Coast Growth Ventures Project located south of Highway 181 and west of Farm-to-Market Road 2986, Gregory, San Patricio County, Texas ~~78387~~78390. This application is being processed in an expedited manner, as allowed by the commission's rules in 30 Texas Administrative Code, Chapter 101, Subchapter J. This link to an electronic map of the site or facility's general location is provided as a public courtesy and not part of the application or notice. For exact location, refer to application. http://www.tceq.texas.gov/assets/public/hb610/index.html?lat=27.92979&lng=-97.32191&zoom=13&type=r. The facility will emit the following air contaminants: carbon monoxide, hazardous air pollutants, hydrogen sulfide, nitrogen oxides, organic compounds, particulate matter including particulate matter with diameters of 10 microns or less and 2.5 microns or less, sulfur dioxide, ammonia, ethylene oxide, and sulfuric acid mist. The proposed facility will also emit greenhouse gases.

Comment [WT1]: According to zipmap.net, 78387 is a good distance to the west

Comment [WT2]: We are aware of the internal procedure to include "ammonia" when listed on PI-1 VII.E. However, we maintain that ammonia should not be listed on PI-1 VII.E, and we believe "ammonia" should be included in the public notice.

This application was submitted to the TCEQ on April 19, 2017. The application will be available for viewing and copying at the TCEQ central office, the TCEQ Corpus Christi regional office, and the Bell Whittington Public Library, 2400 Memorial Parkway, Portland, San Patricio County, Texas, beginning the first day of publication of this notice. The facility's compliance file, if any exists, is available for public review in the Corpus Christi regional office of the TCEQ.

The executive director has determined the application is administratively complete and will conduct a technical review of the application.

PUBLIC COMMENT/PUBLIC MEETING You may submit public comments, a request for a public meeting to the Office of the Chief Clerk at the address below. The TCEQ will consider all public comments in developing a final decision on the application. After the deadline for public comments, the executive director will prepare a response to all public comments.

The purpose of a public meeting is to provide the opportunity to submit comments or ask questions about the application. A public meeting about the application will be held if the executive director determines that there is a significant degree of public interest in the application, if requested by an interested person, or if requested by a local legislator. A public meeting is not a contested case hearing.

After technical review of the application is complete, the executive director may prepare a draft permit and will issue a preliminary decision on the application. Notice of Application and Preliminary Decision for an Air Quality Permit will then be published and mailed to those who made comments, submitted hearing requests or are on the mailing list for this application. That notice will contain the final deadline for submitting public comments.

OPPORTUNITY FOR A CONTESTED CASE HEARING You may request a contested case hearing regarding the portions of the application for State Air Quality Permit Number 146425, and for PSD Air Quality Permit Number PSDTX1518. There is no opportunity to request a contested case hearing regarding the portion of

the application for GHG PSD Air Quality Permit Number GHGPSDTX170. A contested case hearing is a legal proceeding similar to a civil trial in state district court. A contested case hearing will only be granted based on disputed issues of fact that are relevant and material to the Commission's decision on the portions of the application for State Air Quality Permit Number 146425, and for PSD Air Quality Permit Number PSDTX1518. Further, the Commission will only grant a hearing on those issues submitted during the public comment period and not withdrawn.

A person who may be affected by emissions of air contaminants, other than GHGs, from the facility is entitled to request a hearing. If requesting a contested case hearing, you must submit the following: (1) your name (or for a group or association, an official representative), mailing address, and daytime phone number; (2) applicant's name and permit number; (3) the statement "[I/we] request a contested case hearing"; (4) a specific description of how you would be adversely affected by the application and air emissions from the facility in a way not common to the general public; (5) the location and distance of your property relative to the facility; (6) a description of how you use the property which may be impacted by the facility; and (7) a list of all disputed issues of fact that you submit during the comment period. If the request is made by a group or an association, one or more members who have standing to request a hearing must be identified by name and physical address. The interests which the group or association seeks to protect, must also be identified. You may also submit your proposed adjustments to the application/permit which would satisfy your concerns.

Additional notice will be provided. If a hearing request is timely filed, following the close of all applicable comment and request periods, the Executive Director will forward the applicable portion of the application and any requests for contested case hearing to the Commissioners for their consideration at a scheduled Commission meeting. The Commission may only grant a request for a contested case hearing on issues the requestor submitted in their timely comments that were not subsequently withdrawn. **If a hearing is granted, the subject of a hearing will be limited to disputed issues of fact or mixed questions of fact and law relating to relevant and material air quality concerns submitted during the comment period.** Issues such as property values, noise, traffic safety, and zoning are outside of the Commission's jurisdiction to address in this proceeding.

MAILING LIST In addition to submitting public comments, you may ask to be placed on a mailing list to receive future public notices for this specific application mailed by the Office of the Chief Clerk by sending a written request to the Office of the Chief Clerk at the address below.

AGENCY CONTACTS AND INFORMATION Public comments and requests must be submitted either electronically at www.tceq.texas.gov/about/comments.html, or in writing to the Texas Commission on Environmental Quality, Office of the Chief Clerk, MC-105, P.O. Box 13087, Austin, Texas 78711-3087. Any personal information you submit to the TCEQ will become part of the agency's record; this includes email addresses. For more information about this permit application or the permitting process, please call the Public Education Program toll free at 1-800-687-4040. Si desea información en Español, puede llamar al 1-800-687-4040.

Further information may also be obtained from GCGV Asset Holding LLC, 10375 Richmond Avenue, Suite 1800, Houston, Texas 77042-4188 or by calling Mrs. Tammy Headrick, ~~ExxonMobil Chemical Company~~GCGV Asset Holding, at (832) 625-4775.

Notice Issuance Date: April 20, 2017

Degrees Minutes Seconds to Decimal Degrees

Enter Degrees Minutes Seconds latitude:	27	55	47.26
Enter Degrees Minutes Seconds longitude:	97	19	18.89

Convert to Decimal | Clear Values

Results: Latitude: 27.929794 Longitude: 97.321914

Bell Whittington Public Library

2400 Memorial Parkway
Portland, TX 78374

Contact

361-777-0921

Hours

Monday -Thursday 9AM-8PM
Friday 9AM-5PM Saturday
10AM-2PM Sunday Closed

County Judge

Judge Terry A. Simpson

400 West Sinton Street #109
Sinton, TX 78387

Phone: 361-364-9301
Fax: 361-364-6118

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: **GCGV Asset Holding LLC**		
Texas Secretary of State Charter/Registration Number (if applicable): **802522337**		
B. Company Official Contact Information: (☒ Mr. ☐ Mrs. ☐ Ms. ☐ Other:) ______		
Name: **William H Cheek**		
Title: **President, GCGV Asset Holding**		
Mailing Address: **10375 Richmond Avenue, Suite 1800**		
City: **Houston**	State: **Texas**	ZIP Code: **77042**
Telephone No.: **832-625-4775**	Fax No.:	
E-mail Address:		
All permit correspondence will be sent via regular mail unless electronic copies are specifically requested. The company official must initial here if electronic correspondence is requested. ______		
C. Technical Contact Name Information: (☐ Mr. ☒ Mrs. ☐ Ms. ☐ Other:) ______		
Name: **Tammy Headrick**		
Title: **Environmental Advisor, GCGV Asset Holding**		
Company Name: **ExxonMobil Chemical Company**		
Mailing Address: **10375 Richmond Avenue, Suite 1800**		
City: **Houston**	State: **Texas**	ZIP Code: **77042**
Telephone No.: **832-625-4775**	Fax No.:	
E-mail Address: **tammy.headrick@exxonmobil.com**		
D. Site Name: **Gulf Coast Growth Ventures (GCGV)**		
E. Area Name/Type of Facility: **Olefins, Derivatives, & Utilities**		☒ Permanent ☐ Portable
For portable units, please provide the serial number of the equipment being authorized below.		
Serial No:	Serial No:	
F. Principal Company Product or Business: **Organic Chemicals Manufacturing**		
Principal Standard Industrial Classification Code (SIC): **2869**		
Principal North American Industry Classification System (NAICS): **325199**		
G. Projected Start of Construction Date: **2Q2018**		
Projected Start of Operation Date: **2021-2022**		

I. Applicant Information (continued)			
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):			
Street Address: **south of Highway 181 and west of FM2986**			
City/Town:	County: **San Patricio**		ZIP Code:
Latitude (nearest second): **27°55'47.26"**		Longitude (nearest second): **97°19'18.89"**	
I. Account Identification Number (leave blank if new site or facility):			
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):			
L. Regulated Entity Number (RN):			
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, notice of violation, or enforcement action? If Yes, attach a copy of any correspondence from the agency and provide the RN in section I.L. above.			☐ YES ☒ NO
C. Number of New Jobs: **600**			
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:			
State Senator: **Judith Zaffrini**			District No.: **21**
State Representative: **J. M. Lozano**			District No.: **43**
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	☐ Plant-Wide Applicability Limit
☒ Prevention of Significant Deterioration (PSD)		☐ Hazardous Air Pollutant Major Source	
☒ PSD for greenhouse gases (GHGs)		☐ Other:_____	

III.	**Type of Permit Action Requested *(continued)***		
D.	Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC § 116.315(c).		☐ YES ☒ NO
E.	Is this application for a change of location of previously permitted facilities?		☐ YES ☒ NO
If Yes, complete all parts of III.E.			
Current Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
Proposed Location of Facility (If no street address, provide clear driving directions to the site in writing.):			
Street Address:			
City:	County:	ZIP Code:	
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
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:			
G.	Are you permitting planned maintenance, startup, and shutdown emissions?		☒ YES ☐ NO
If Yes, attach information on any changes to emissions under this application as specified in VII and VIII.			
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability)		
Is this facility located at a site required to obtain a federal operating permit?		☒ YES ☐ NO ☐ To be determined	
If Yes, list all associated permit number(s), attach pages as needed).			
Associated Permit No (s.): **TBD**			
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	
☐ Operational Flexibility/Off-Permit Notification		☐ Streamlined Revision for GOP	
☒ To be Determined		☐ None	

III. Type of Permit Action Requested *(continued)*	
H. Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
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 all parts of V.D.	☐ 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. If this is an application for emissions of GHGs, select one of the following:	
☐ separate public notice (requires a separate application)	☒ consolidated public notice
E. 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).	
List:	
F. Is this a state permit amendment application? If Yes, complete all parts of IV.F.	
Is there any change in character of emissions in this application?	☐ YES ☐ NO
Is there a new air contaminant in this application?	☐ YES ☐ NO
Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
List the total annual emission increases associated with the application ***(List all that apply and attach additional sheets as needed):***	
Volatile Organic Compounds (VOC): **917.79 tpy**	
Sulfur Dioxide (SO_2): **37.71 tpy**	
Carbon Monoxide (CO): **1,346.07 tpy**	
Nitrogen Oxides (NO_x): **505.14 tpy**	
Particulate Matter (PM): **184.55 tpy**	
PM 10 microns or less (PM_{10}): **175.08 tpy**	
PM 2.5 microns or less ($PM_{2.5}$): **166.24 tpy**	
Lead (Pb):	
Hazardous Air Pollutants (HAPs):	
Other speciated air contaminants not listed above: **Sulfuric Acid (H_2SO_4):1.04 tpy Ammonia (NH_3):116.53**	

V. **Public Notice Information** ***(complete if applicable)***			
A. Responsible Person: (☐ Mr. ☒ Mrs. ☐ Ms. ☐ Other:) ______			
Name: **Tammy Headrick**			
Title: **Environmental Advisor, GCGV Asset Holding**			
Company Name: **ExxonMobil Chemical Company**			
Mailing Address: **10375 Richmond Avenue, Suite 1800**			
City: **Houston**	State: **Texas**	ZIP Code: **77042**	
Telephone No.: **832-625-4775**	Fax No.:		
E-mail Address: **tammy.headrick@exxonmobil.com**			
B. Technical Contact: (☐ Mr. ☒ Mrs. ☐ Ms. ☐ Other:) ______			
Name: **Tammy Headrick**			
Title: **Environmental Advisor, GCGV Asset Holding**			
Mailing Address: **10375 Richmond Avenue, Suite 1800**			
City: **Houston**	State: **Texas**	ZIP Code: **77042**	
Telephone No.: **832-625-4775**	Fax No.:		
E-mail Address: **tammy.headrick@exxonmobil.com**			
C. Name of the Public Place: **Bell-Whittington Public Library**			
Physical Address *(No P.O. Boxes)*: **2400 Memorial Pkwy**			
City: **Portland**	County: **San Patricio**	ZIP Code: **78374**	
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 ☐ NO
D. Concrete Batch Plants, PSD, and Nonattainment Permits			
County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable: **Terry A. Simpson**			
Mailing Address: **400 West Sinton Street #109**			
City: **Sinton**	State: **TX**	ZIP Code: **78387**	

V.	**Public Notice Information *(complete if applicable)***		
D.	Concrete Batch Plants, PSD, and Nonattainment Permits *(continued)*		
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:	
Provide the name, mailing address of the chief executive for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	
Provide the name, mailing address of the Indian Governing Body for the location where the facility is or will be located.			
Indian Governing Body:			
Mailing Address:			
City:	State:	ZIP Code:	
Identify the Federal Land Manager(s) for the location where the facility is or will be located.			
Federal Land Manager(s):			
E.	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)***		
☒ Current Area Map		
☒ Plot Plan		
☐ Existing Authorizations **There are no existing authorizations**		
☒ Process Flow Diagram		
☒ Process Description		
☒ Maximum Emissions Data and Calculations		
☒ Air Permit Application Tables		
☒ Table 1(a) (Form 10153) entitled, Emission Point Summary		
☒ Table 2 (Form 10155) entitled, Material Balance		
☒ Other equipment, process or control device tables		
B. Are any schools located within 3,000 feet of this facility?		☐ YES ☒ NO
C. Maximum Operating Schedule:		
Hour(s): **8760**	Day(s): **365**	
Week(s): **52**	Year(s):	
Seasonal Operation? If Yes, please describe in the space provide below.		☐ YES ☒ NO
Hour(s):	Day(s):	
Week(s):	Year(s):	
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.		
MSS Facility(s) or Activity	**Year(s)**	
E. Does this application involve any air contaminants for which a disaster review is required?		☒ YES ☐ NO
If Yes, list which air contaminants require a disaster review.		
Ethylene Oxide		

VII.	**Technical Information *(continued)***	
F.	Does this application include a pollutant of concern on the Air Pollutant Watch List (APWL)?	☐ YES ☒ NO
G.	Are emissions of GHGs associated with this project subject to PSD?	☒ YES ☐ NO
If "yes," provide a list of all associated applications for this project:		
GHG emissions are included in this application		
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
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: $75000.00	
Paid online?	☐ YES ☒ NO
Company name on check: **Sage ATC Environmental Consulting LLC**	
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

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; the Texas Health and Safety Code, Chapter 382, the Texas Clean Air Act (TCAA) the air quality rules 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: **William H Cheek**
Signature: WH Cheek *Original Signature Required*
Date: 4/12/17

TCEQ

TCEQ Core Data Form

TCEQ Use Only

For detailed instructions regarding completion of this form, please read the Core Data Form Instructions or call 512-239-5175.

SECTION I: General Information

1. Reason for Submission (If other is checked please describe in space provided.)

[X] New Permit, Registration or Authorization (Core Data Form should be submitted with the program application.)

[ ] Renewal (Core Data Form should be submitted with the renewal form) | [ ] Other

2. Customer Reference Number (if issued)	Follow this link to search for CN or RN numbers in **Central Registry****	3. Regulated Entity Reference Number (if issued)
CN TBD		RN TBD

SECTION II: Customer Information

4. General Customer Information	5. Effective Date for Customer Information Updates (mm/dd/yyyy)	

[X] New Customer [ ] Update to Customer Information [ ] Change in Regulated Entity Ownership
[ ] Change in Legal Name (Verifiable with the Texas Secretary of State or Texas Comptroller of Public Accounts)

The Customer Name submitted here may be updated automatically based on what is current and active with the Texas Secretary of State (SOS) or Texas Comptroller of Public Accounts (CPA).

6. Customer Legal Name (If an individual, print last name first: e.g.: Doe, John)	If new Customer, enter previous Customer below:
GCGV Asset Holding LLC	

7. TX SOS/CPA Filing Number	8. TX State Tax ID (11 digits)	9. Federal Tax ID (9 digits)	10. DUNS Number (if applicable)
802522337	32061311067	81-204507	

11. Type of Customer: [X] Corporation [ ] Individual Partnership: [ ] General [ ] Limited
Government: [ ] City [ ] County [ ] Federal [ ] State [ ] Other [ ] Sole Proprietorship [ ] Other:

12. Number of Employees
[ ] 0-20 [ ] 21-100 [ ] 101-250 [ ] 251-500 [X] 501 and higher

13. Independently Owned and Operated?
[X] Yes [ ] No

14. Customer Role (Proposed or Actual) - as it relates to the Regulated Entity listed on this form. Please check one of the following:

[X] Owner [ ] Operator [ ] Owner & Operator
[ ] Occupational Licensee [ ] Responsible Party [ ] Voluntary Cleanup Applicant [ ] Other:

15. Mailing Address:	22777 Springwoods Village Parkway						
	c/o Bill Cheek						
	City	Springs	State	TX	ZIP	77389	ZIP + 4

16. Country Mailing Information (if outside USA)	17. E-Mail Address (if applicable)

18. Telephone Number	19. Extension or Code	20. Fax Number (if applicable)
( ) -		( ) -

SECTION III: Regulated Entity Information

21. General Regulated Entity Information (If 'New Regulated Entity" is selected below this form should be accompanied by a permit application)

[X] New Regulated Entity [ ] Update to Regulated Entity Name [ ] Update to Regulated Entity Information

The Regulated Entity Name submitted may be updated in order to meet TCEQ Agency Data Standards (removal of organizational endings such as Inc, LP, or LLC).

22. Regulated Entity Name (Enter name of the site where the regulated action is taking place.)

GCGV ~~Asset Holding LLC~~ Project

APR 19 2017
APIRT

23. Street Address of the Regulated Entity: (No PO Boxes)	22777 Springwoods Village Parkway							
	City	Springs	State	TX	ZIP	77389	ZIP + 4	
24. County								

Enter Physical Location Description if no street address is provided.

25. Description to Physical Location:	south of Highway 181 and west of FM2986		
26. Nearest City		State	Nearest ZIP Code
Gregory		TX	78387

27. Latitude (N) In Decimal:	27.929794		28. Longitude (W) In Decimal:	97.321914	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds
27	55	47.26	97	19	18.89

29. Primary SIC Code (4 digits)	30. Secondary SIC Code (4 digits)	31. Primary NAICS Code (5 or 6 digits)	32. Secondary NAICS Code (5 or 6 digits)
2869		325199	

33. What is the Primary Business of this entity? (Do not repeat the SIC or NAICS description.)

Organic Chemicals Manufacturing

34. Mailing Address:	22777 Springwoods Village Parkway							
	c/o Bill Cheek							
	City	Springs	State	TX	ZIP	78387	ZIP + 4	
35. E-Mail Address:								

36. Telephone Number	37. Extension or Code	38. Fax Number (if applicable)
( ) -		( ) -

39. TCEQ Programs and ID Numbers Check all Programs and write in the permits/registration numbers that will be affected by the updates submitted on this form. See the Core Data Form instructions for additional guidance.

☐ Dam Safety	☐ Districts	☐ Edwards Aquifer	☐ Emissions Inventory Air	☐ Industrial Hazardous Waste
☐ Municipal Solid Waste	☐ New Source Review Air	☐ OSSF	☐ Petroleum Storage Tank	☐ PWS
☐ Sludge	☐ Storm Water	☐ Title V Air	☐ Tires	☐ Used Oil
☐ Voluntary Cleanup	☒ Waste Water	☐ Wastewater Agriculture	☐ Water Rights	☐ Other:
	Submit concurrently			

SECTION IV: Preparer Information

40. Name: Tammy Headrick			41. Title: Environmental Advisor, ExxonMobil Chemical
42. Telephone Number	43. Ext./Code	44. Fax Number	45. E-Mail Address
(832) 625 - 4775		( ) -	tammy.headrick@exxonmobil.com

SECTION V: Authorized Signature

46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 6 and/or as required for the updates to the ID numbers identified in field 39.

Company:	GCGV Asset Holding LLC	Job Title:	President, GCGV Asset Holding
Name(*In Print*):	William H Cheek	Phone:	(832)624-3479
Signature:	WH Cheek	Date:	4/12/17

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

Include estimated cost of the equipment and services that would normally be capitalized according to standard and generally accepted corporate financing and accounting procedures. Tables, checklists, and guidance documents pertaining to air quality permits are available from the Texas Commission on Environmental Quality, Air Permits Division Web site at **www.tceq.texas.gov/nav/permits/air_permits.html**.

I.	**Direct Costs [30 TAC § 116.141(c)(1)]**		**Estimated Capital Cost**
	A.	A process and control equipment not previously owned by the applicant and not currently authorized under this chapter.	$
	B.	Auxiliary equipment, including exhaust hoods, ducting, fans, pumps, piping, conveyors, stacks, storage tanks, waste disposal facilities, and air pollution control equipment specifically needed to meet permit and regulation requirements.	$
	C.	Freight charges	$
	D.	Site preparation, including demolition, construction of fences, outdoor lighting, road, and parking areas.	$
	E.	Installation, including foundations, erection of supporting structures, enclosures or weather protection, insulation and painting, utilities and connections, process integration, and process control equipment.	$
	F.	Auxiliary buildings, including materials storage, employee facilities, and changes to existing structures.	$
	G.	Ambient air monitoring network.	$
II.	**Indirect Costs [30 TAC § 116.141(c)(2)]**		**Estimated Capital Cost**
	A.	Final engineering design and supervision, and administrative overhead.	$
	B.	Construction expense, including construction liaison, securing local building permits, insurance, temporary construction facilities, and construction clean-up.	$
	C.	Contractor's fee and overhead.	$
	Total Estimated Capital Cost		$ **>7,500,000**

Texas Commission on Environmental Quality
Table 30
Estimated Capital Cost and Fee Verification

I certify that the total estimated capital cost of the project as defined in 30 TAC § 116.141 is equal to or less than the above figure. I further state that I have read and understand Texas Water Code § 7.179, which defines Criminal Offenses for certain violations, including intentionally or knowingly making, or causing to be made, false material statements or representations.

Company Name: **GCGV Asset Holding LLC**

Company Representative Name *(please print)*: **William H Cheek**

Title: **President, GCGV Asset Holding**

Company Representative Signature: W H Cheek

Estimated Capital Cost		Permit Application Fee	GHG*/PSD/Nonattainment Application Fee
Less than	\$300,000	\$900 (minimum fee)	\$3,000 (minimum fee)
\$300,000 to	\$25,000,000	0.30% of capital cost	
\$300,000 to	\$7,500,000		1.0% of capital cost
Greater than	\$25,000,000	\$75,000 (maximum fee)	
Greater than	\$7,500,000		\$75,000 (maximum fee)

*A single PSD fee (calculated on the capital cost of the project per 30 TAC § 116.163) will be required for all of the associated permitting actions for a GHG PSD project. Other NSR permit fees related to the project that have already been remitted to the TCEQ can be subtracted when determining the appropriate fee to submit with the GHG PSD application; please identify these other fees in the GHG PSD permit application.

Permit Application Fee (from table above) = **\$75,000**

Date: 4/12/17

EXPEDITE

GCGV Asset Holding LLC
10375 Richmond Avenue
Houston, TX 77042

GULF COAST
GROWTH VENTURES

April 19, 2017

Texas Commission on Environmental Quality
Air Permits Division (MC163)
P.O. Box 13088
Austin, Texas 78711-3088

Hand Delivered

Re: New Source Review (NSR) / Prevention of Significant Deterioration (PSD) Application
Request for Expedited Permitting Program
Gulf Coast Growth Ventures Project

To Whom It May Concern:

On behalf of Gulf Coast Growth Ventures (GCGV) Asset Holding LLC, and in accordance with 30 TAC §101.600, this letter requests expedited processing for the PSD application to TCEQ to authorize the Gulf Coast Growth Ventures Project. Attached please find a completed and signed Form APD-EXP. The surcharge check is being provided concurrently with this letter.

If you have any questions, please contact Tammy Headrick at 832-625-4775 or via email at tammy.headrick@exxonmobil.com.

Sincerely,

Shawn E Simmons

Shawn E Simmons, PhD
Environmental & Permitting Manager
Exxon Mobil Chemical Company

Attachments

AIR PERMITS DIVISION
APR 19 2017
HAND-DELIVERED

APR 19 2017
APIRT

19 APR 2017 PM 4:29 TCEQ APD

AIR PERM.. S DIVISION

APR 19 2017

HAND-DELIVERED

GCGV Asset Holding LLC
10375 Richmond Avenue
Houston, TX 77042

GULF COAST GROWTH VENTURES

April 19, 2017

Texas Commission on Environmental Quality
Air Permits Division (MC163)
P.O. Box 13088
Austin, Texas 78711-3088

Hand Delivered

Re: New Source Review (NSR) / Prevention of Significant Deterioration (PSD) Application
Initial Permit Application
Gulf Coast Growth Ventures Project

To Whom It May Concern:

On behalf of Gulf Coast Growth Ventures (GCGV) Asset Holding LLC, attached is a New Source Review (NSR) / Prevention of Significant Deterioration (PSD) application for a grassroots industrial organic chemicals manufacturing complex known as the Gulf Coast Growth Ventures site. The project triggers PSD review for several pollutants. The application contains all of the elements of a complete application per 30 Texas Administrative Code §116.111, including: pertinent technical descriptions and emission calculations; Federal Applicability; PSD Best Available Control Technology (BACT), including RACT/BACT/LAER Clearinghouse results; regulatory review and other discussions; required TCEQ forms; area map, plot plan, and process flow diagrams. The application consists of two volumes: Volume I for traditional pollutants and Volume II for Greenhouse Gas (GHG) pollutants. Appendix A of Volume I, as well as Appendix B of Volume II, include confidential information specifically protected from disclosure by Section 552.110 of the Texas Public Information Act. This information has been conspicuously marked on each page as "Confidential Business Information".

A request for expedited permitting is being made for this application.

If you have any questions, please contact Tammy Headrick at 832-625-4775 or via email at tammy.headrick@exxonmobil.com.

Sincerely,

Shawn E Simmons, PhD
Environmental & Permitting Manager
Exxon Mobil Chemical Company

Attachments

19 APR 2017 PM 4:29 TCEQ APD

GCGV Asset Holding LLC
10375 Richmond Avenue
Houston, TX 77042

cc: Kelly Ruble, TCEQ Region 14
Air Permits Section (6PD-R), EPA Region 6

SAGE ATC
ENVIRONMENTAL CONSULTING

GULF COAST GROWTH VENTURES

Prevention of Significant Deterioration Permit Application for Gulf Coast Growth Ventures Project (GCGV)

Volume I: PSD Application

GCGV Asset Holding LLC

Gregory, Texas

April 2017

AIR PERMITS DIVISION
APR 19 2017
HAND-DELIVERED

715 DISCOVERY BLVD., SUITE 301 • CEDAR PARK, TEXAS • 78613 • 512/258-8500 • FAX 512/258-7522

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SECTION 1
TCEQ ADMINISTRATIVE FORMS

1.1 Administrative Forms

The following forms and tables are included in this section in the following order, in support of this application:

- Form PI-1 – General Application for Air Preconstruction Permits and Amendments;
- Core Data Form;
- Table 30 – Permit Fee;
- Copy of Permit Fee;
- PE Certification;
- Form APD-EXP;
- Form APD-APS;
- Table 1(a) – Emission Point Summary; and
- Table 1F – Air Quality Application Supplement.

PROFESSIONAL ENGINEER CERTIFICATION

I, Randy D. Parmley, a registered professional engineer in the State of Texas (Registration No. 75280) certify that the attached Texas Commission on Environmental Quality (TCEQ) Air Permit Application associated with the Gulf Coast Growth Venture project, dated April 2017, was prepared by me and/or by other staff under my direction, as based on the information provided by GCGV Asset Holding LLC.

Randy D Parmley, P.E.
Engineer

Randy D. Parmley
Signature

75280
Registration Number

Texas
State

SEAL

STATE OF TEXAS
RANDY D. PARMLEY
75280
REGISTERED
PROFESSIONAL ENGINEER

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	**Apr 2017**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**TBD**
Area Name:	**Gulf Coast Growth Ventures (GCGV)**			**Customer Reference No.:**	**TBD**

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND PER HOUR**	**(B) TONS PER YEAR**
O_FAF01	O_FAF01	Furnace A	(1)	(1)	(1)
O_FBF01	O_FBF01	Furnace B	(1)	(1)	(1)
O_FCF01	O_FCF01	Furnace C	(1)	(1)	(1)
O_FDF01	O_FDF01	Furnace D	(1)	(1)	(1)
O_FEF01	O_FEF01	Furnace E	(1)	(1)	(1)
O_FFF01	O_FFF01	Furnace F	(1)	(1)	(1)
O_FGF01	O_FGF01	Furnace G	(1)	(1)	(1)
O_FHF01	O_FHF01	Furnace H	(1)	(1)	(1)
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	NO_X	53.70	196.22
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	CO	1,640.59	635.32
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	$PM/PM_{10}/PM_{2.5}$	34.53	92.85
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	VOC	24.99	67.20
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	SO2	2.73	7.33
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	H_2SO_4	0.25	0.67
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	NH_3	30.08	77.46

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
UFFLARE01	UFFLARE01	Multi-point Ground Flare	NO_X	2,758.17	(3)
UFFLARE01	UFFLARE01	Multi-point Ground Flare	CO	4,218.81	(3)
UFFLARE01	UFFLARE01	Multi-point Ground Flare	VOC	5,944.74	(3)
UFFLARE01	UFFLARE01	Multi-point Ground Flare	SO_2	564.36	(3)
UFFLARE02	UFFLARE02	Shared Elevated Flare	NO_X	68.66	(3)
UFFLARE02	UFFLARE02	Shared Elevated Flare	CO	349.86	(3)
UFFLARE02	UFFLARE02	Shared Elevated Flare	VOC	916.17	(3)
UFFLARE02	UFFLARE02	Shared Elevated Flare	SO_2	31.54	(3)
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	NO_X	(2)	149.36
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	CO	(2)	300.72
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	VOC	(2)	320.06
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	SO_2	(2)	5.42
O_FUG	O_FUG	Olefins Unit Fugitives	VOC	13.52	59.23
O_FUG	O_FUG	Olefins Unit Fugitives	NH_3	2.00	8.76
O_FUG	O_FUG	Olefins Unit Fugitives	CO	0.04	0.16
O_FUG	O_FUG	Olefins Unit Fugitives	H_2SO_4	<0.01	0.02

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

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Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
O_FUG	O_FUG	Olefins Unit Fugitives	H_2S	0.02	0.07
O_FUG	O_FUG	Olefins Unit Fugitives	NaOH	<0.01	<0.01
O_ACV	O_ACV	Olefins Regeneration Vent	VOC	0.18	0.06
O_ACV	O_ACV	Olefins Regeneration Vent	CO	9.98	1.80
GFFLARE03	GFFLARE03	Glycol Elevated Flare	NO_X	61.02	17.84
GFFLARE03	GFFLARE03	Glycol Elevated Flare	CO	310.95	90.91
GFFLARE03	GFFLARE03	Glycol Elevated Flare	VOC	214.98	17.66
GFFLARE03	GFFLARE03	Glycol Elevated Flare	SO_2	22.74	8.66
GFFLARE03	GFFLARE03	Glycol Elevated Flare	HCl	1.11	0.49
GX202	GX202	Glycol Thermal Oxidizer	NO_X	13.16	42.44
GX202	GX202	Glycol Thermal Oxidizer	CO	11.06	35.65
GX202	GX202	Glycol Thermal Oxidizer	VOC	38.01	83.86
GX202	GX202	Glycol Thermal Oxidizer	SO2	1.75	7.52
GX202	GX202	Glycol Thermal Oxidizer	$PM/PM_{10}/PM_{2.5}$	1.00	3.23
GX202	GX202	Glycol Thermal Oxidizer	HCl	1.11	4.86
GX202	GX202	Glycol Thermal Oxidizer	NH_3	0.04	<0.01

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

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Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
GD503A	GD503A	Glycol Vacuum Vent A	VOC	(5)	(5)
GD503B	GD503B	Glycol Vacuum Vent B	VOC	(5)	(5)
GDVAC	GDVAC	Glycol Vacuum System Cap	VOC	3.43	15.03
GD103	GD103	Glycol Moderator	VOC	4.79	0.04
GFUG	GFUG	Glycol Unit Fugitives	VOC	2.27	9.96
GFUG	GFUG	Glycol Unit Fugitives	CO	<0.01	0.03
UCCT01	UCCT01	Utilities Cooling Tower	VOC	230.58	91.13
UCCT01	UCCT01	Utilities Cooling Tower	PM	8.07	31.56
UCCT01	UCCT01	Utilities Cooling Tower	PM10	5.65	22.09
UCCT01	UCCT01	Utilities Cooling Tower	PM2.5	3.39	13.26
USSG01A	USSG01A	Utilities Boiler A	(6)	(6)	(6)
USSG01B	USSG01B	Utilities Boiler B	(6)	(6)	(6)
USSG01C	USSG01C	Utilities Boiler C	(6)	(6)	(6)
USSG01CAP	USSG01CAP	Utilities Boiler Cap	NO_X	35.25	69.02
USSG01CAP	USSG01CAP	Utilities Boiler Cap	CO	176.74	239.40
USSG01CAP	USSG01CAP	Utilities Boiler Cap	$PM/PM_{10}/PM_{2.5}$	20.86	47.57

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
USSG01CAP	USSG01CAP	Utilities Boiler Cap	VOC	15.09	34.43
USSG01CAP	USSG01CAP	Utilities Boiler Cap	SO_2	1.65	3.76
USSG01CAP	USSG01CAP	Utilities Boiler Cap	H_2SO_4	0.15	0.35
USSG01CAP	USSG01CAP	Utilities Boiler Cap	NH_3	16.10	29.07
UFF01_A	UFF01_A	Shared Thermal Oxidizer A	(7)	(7)	(7)
UFF01_B	UFF01_B	Shared Thermal Oxidizer B	(7)	(7)	(7)
UFF01	UFF01	Shared Thermal Oxidizer Cap	NO_X	18.80	29.11
UFF01	UFF01	Shared Thermal Oxidizer Cap	CO	25.81	39.95
UFF01	UFF01	Shared Thermal Oxidizer Cap	$PM/PM_{10}/PM_{2.5}$	2.34	3.61
UFF01	UFF01	Shared Thermal Oxidizer Cap	VOC	114.96	63.33
UFF01	UFF01	Shared Thermal Oxidizer Cap	SO_2	1.13	4.97
U_FUG	U_FUG	Utilities Fugitives	VOC	1.60	7.01
U_FUG	U_FUG	Utilities Fugitives	NH_3	0.22	0.96
U_FUG	U_FUG	Utilities Fugitives	CO	<0.01	0.02
U_FUG	U_FUG	Utilities Fugitives	H_2SO_4	<0.01	<0.01
U_GEN1	U_GEN1	Emergency Generator No. 1	(8)	(8)	(8)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
U_GEN2	U_GEN2	Emergency Generator No. 2	(8)	(8)	(8)
U_GEN3	U_GEN3	Emergency Generator No. 3	(8)	(8)	(8)
U_GEN4	U_GEN4	Emergency Generator No. 4	(8)	(8)	(8)
U_GEN5	U_GEN5	Emergency Generator No. 5	(8)	(8)	(8)
U_FWP	U_FWP	Firewater Pump No. 1	(8)	(8)	(8)
G_GEN6	G_GEN6	Glycol Generator No. 1	(8)	(8)	(8)
ENGINECAP	ENGINECAP	Engine Cap	NO_X	16.79	0.84
ENGINECAP	ENGINECAP	Engine Cap	CO	27.93	1.40
ENGINECAP	ENGINECAP	Engine Cap	$PM/PM_{10}/PM_{2.5}$	1.04	0.05
ENGINECAP	ENGINECAP	Engine Cap	VOC	15.96	0.80
ENGINECAP	ENGINECAP	Engine Cap	SO_2	0.04	<0.01
U_LLOAD	U_LLOAD	Rail/Truck Liquid Loading	VOC	10.79	10.08
WWTP	WWTP	Wastewater System	VOC	3.00	13.12
WWTP	WWTP	Wastewater System	NH_3	0.02	0.11
WWTP	WWTP	Wastewater System	Acetone	<0.01	<0.01
WWTP	WWTP	Wastewater System	H_2S	0.02	0.10

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
WWTP	WWTP	Wastewater System	Phosphine	<0.01	0.04
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	VOC	527.72	6.54
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	$PM/PM_{10}/PM_{2.5}$	13.13	0.08
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	NO_X	1.86	0.08
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	CO	4.40	0.20
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	SO_2	0.28	0.01
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	VOC	181.45	3.25
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	NO_X	1.86	0.22
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	CO	4.40	0.53
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	$PM/PM_{10}/PM_{2.5}$	0.15	0.02
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	SO_2	0.28	0.03
REFUSTN	REFUSTN	Vehicle Refueling Station	VOC	3.13	2.23
E_LLDS_001	ELLDS_001	Granular Feed bin transfer air Vent	(9)	(9)	(9)
E_DLDS_002	EDLDS_002	Product Purge bin Screener Dust Collector Vent	(9)	(9)	(9)
E_LLFB_001	ELLFB_001	Feed bin exit Dust collector Vent	(9)	(9)	(9)
E_DLSB_002	EDLSB_002	Seed bed bin Dust collector Vent	(9)	(9)	(9)

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
E_MEXT_001	EMEXT_001	Extruder Feed Hopper Vent	(9)	(9)	(9)
E_DLSB_001	EDLSB_001	Granule Filter Receiver (seed bed filter)	(9)	(9)	(9)
E_PLDS_006	EPLDS_006	Line 1 - Prime Pellet Silo Vent 01	(9)	(9)	(9)
E_PLDS_007	EPLDS_007	Line 1 - Prime Pellet Silo Vent 02	(9)	(9)	(9)
E_PLDS_008	EPLDS_008	Line 1 - Prime Pellet Silo Vent 03	(9)	(9)	(9)
E_PLDS_009	EPLDS_009	Line 1 - Prime Pellet Silo Vent 04	(9)	(9)	(9)
E_PLDS_010	EPLDS_010	Line 1 - Prime Pellet Silo Vent 05	(9)	(9)	(9)
E_MPPS_001	EMPPS_001	Line 1 - Pellet Surge Bin Vent	(9)	(9)	(9)
E_MPPS_002	EMPPS_002	Line 1 - Pellet Dryer Vent-01	(9)	(9)	(9)
E_MPPS_003	EMPPS_003	Line 1 - Pellet Dryer Vent-02	(9)	(9)	(9)
E_MPPX_001	EMPPX_001	Line 1 - Film Test Extruder Filter Receiver	(9)	(9)	(9)
E_LFBF_001	ELFBF_001	Finishing Building Vacuum System Dust Collector	(9)	(9)	(9)
E_LADD_001	ELADD_001	Line 1 - Additive Feed Hopper Blower Vent	(9)	(9)	(9)
E_LADD_002	ELADD_002	Line 1 - Additive Drying Hopper Dust Collector	(9)	(9)	(9)
E_LADD_004	ELADD_004	Line 1 - Vacuum Blower-01 Vent for Additive AB Transfer	(9)	(9)	(9)
E_LADD_005	ELADD_005	Line 1 - Vacuum Blower-03 Vent for Additive Transfer	(9)	(9)	(9)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

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Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
E_LADD_006	ELADD_006	Lines 1 - Vacuum Blower-05 Vent for Additive Transfer	(9)	(9)	(9)
E_LADD_004	ELADD_007	Line 1 - Additive Dump Station Vent Dust Collector	(9)	(9)	(9)
E_BCTS_001	EBCTS_001	Line 1 - Cylinder Vent Filter-01	(9)	(9)	(9)
E_BCTS_002	EBCTS_002	Line 1 - Cylinder Vent Filter-02	(9)	(9)	(9)
E_BCTS_003	EBCTS_003	Line 1 - Cylinder Vent Filter-03	(9)	(9)	(9)
E_BCTS_004	EBCTS_004	Line 1 - Catalyst Hold Tank Filter-04	(9)	(9)	(9)
E_BCTS_005	EBCTS_005	Line 1 - Catalyst Hold Tank Filter-05	(9)	(9)	(9)
E_BCTS_006	EBCTS_006	Line 1 - Catalyst Hold Tank Filter-06	(9)	(9)	(9)
E_CR01	ECR01	Line 1 - Reactor startup Nitrogen transfer/purge Vent to ATM	(9)	(9)	(9)
E_VENT CAP	E_VENT CAP	EM PE Vents Cap	VOC	(9)	(9)
E_VENT CAP	E_VENT CAP	EM PE Vents Cap	$PM/PM_{10}/PM_{2.5}$	(9)	(9)
E_FUG	E_FUG	EM PE Unit Fugitives	VOC	(10)	(10)
C_LLDS_001	CLLDS_001	Granular Feed bin transfer air Vent	(9)	(9)	(9)
C_DLDS_002	CDLDS_002	Product Purge bin Screener Dust Collector Vent	(9)	(9)	(9)
C_LLFB_001	CLLFB_001	Feed bin exit Dust collector Vent	(9)	(9)	(9)
C_DLSB_002	CDLSB_002	Seed bed bin Dust collector Vent	(9)	(9)	(9)

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
C_MEXT_001	CMEXT_001	Extruder Feed Hopper Vent	(9)	(9)	(9)
C_DLSB_001	CDLSB_001	Granule Filter Receiver (seed bed filter)	(9)	(9)	(9)
C_PLDS_006	CPLDS_006	Line 2 - Prime Pellet Silo Vent 01	(9)	(9)	(9)
C_PLDS_007	CPLDS_007	Line 2 - Prime Pellet Silo Vent 02	(9)	(9)	(9)
C_PLDS_008	CPLDS_008	Line 2 - Prime Pellet Silo Vent 03	(9)	(9)	(9)
C_PLDS_009	CPLDS_009	Line 2 - Prime Pellet Silo Vent 04	(9)	(9)	(9)
C_PLDS_010	CPLDS_010	Line 2 - Prime Pellet Silo Vent 05	(9)	(9)	(9)
C_MPPS_001	CMPPS_001	Line 2 - Pellet Surge Bin Vent	(9)	(9)	(9)
C_MPPS_002	CMPPS_002	Line 2 - Pellet Dryer Vent-01	(9)	(9)	(9)
C_MPPS_003	CMPPS_003	Line 2 - Pellet Dryer Vent-02	(9)	(9)	(9)
C_MPPX_001	CMPPX_001	Line 2 - Film Test Extruder Filter Receiver	(9)	(9)	(9)
C_LFBF_001	CLFBF_001	Finishing Building Vacuum System Dust Collector	(9)	(9)	(9)
C_LADD_001	CLADD_001	Line 2 - Additive Feed Hopper Blower Vent	(9)	(9)	(9)
C_LADD_002	CLADD_002	Line 2 - Additive Drying Hopper Dust Collector	(9)	(9)	(9)
C_LADD_004	CLADD_004	Line 2 - Vacuum Blower-02 Vent for Additive AB Transfer	(9)	(9)	(9)
C_LADD_005	CLADD_005	Line 2 - Vacuum Blower-04 Vent for Additive Transfer	(9)	(9)	(9)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
C_LADD_006	CLADD_006	Lines 2 - Vacuum Blower-06 Vent for Additive Transfer	(9)	(9)	(9)
C_LADD_004	CLADD_007	Line 2 - Additive Dump Station Vent Dust Collector	(9)	(9)	(9)
C_BCTS_001	CBCTS_001	Line 2 - Cylinder Vent Filter-01	(9)	(9)	(9)
C_BCTS_002	CBCTS_002	Line 2 - Cylinder Vent Filter-02	(9)	(9)	(9)
C_BCTS_003	CBCTS_003	Line 2 - Cylinder Vent Filter-03	(9)	(9)	(9)
C_BCTS_004	CBCTS_004	Line 2 - Catalyst Hold Tank Filter-04	(9)	(9)	(9)
C_BCTS_005	CBCTS_005	Line 2 - Catalyst Hold Tank Filter-05	(9)	(9)	(9)
C_BCTS_006	CBCTS_006	Line 2 - Catalyst Hold Tank Filter-06	(9)	(9)	(9)
C_CR01	CCR01	Line 2 - Reactor startup Nitrogen transfer/purge Vent to ATM	(9)	(9)	(9)
C_VENT CAP	C_VENT CAP	CPE Unit Vents Cap	VOC	(9)	(9)
C_VENT CAP	C_VENT CAP	CPE Unit Vents Cap	$PM/PM_{10}/PM_{2.5}$	(9)	(9)
PE_REGEN	PE_REGEN	PE Treater Regeneration	VOC	<0.01	<0.01
C_FUG	C_FUG	CPE Unit Fugitives	VOC	(10)	(10)
PE_VENT CAP	PE_VENT CAP	PE Unit Vents Cap	VOC	71.36	94.22
PE_VENT CAP	PE_VENT CAP	PE Unit Vents Cap	$PM/PM_{10}/PM_{2.5}$	2.95	5.57
PE_FUG	PE_FUG	PE Unit Fugitives	VOC	4.40	19.26

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
UTTK101T	UTTK101T	Pygas Day Tank 1	(11)	(11)	(11)
UTTK102T	UTTK102T	Pygas Day Tank 2	(11)	(11)	(11)
CAPTPYG	CAPTPYG	Pygas Cap	VOC	2.32	2.61
UTTK103T	UTTK103T	Sulfidic Caustic Day Tank 1	(11)	(11)	(11)
UTTK104T	UTTK104T	Sulfidic Caustic Day Tank 2	(11)	(11)	(11)
CAPTSC	CAPTSC	Sulfidic Caustic Cap	NaOH	0.78	0.17
CAPTSC	CAPTSC	Sulfidic Caustic Cap	VOC	<0.01	<0.01
CAPTSC	CAPTSC	Sulfidic Caustic Cap	H_2S	<0.01	<0.01
UTTK107T	UTTK107T	Light Oil Tank	VOC	3.21	0.59
UTTK100T	UTTK100T	Diesel Day Tank 1	VOC	0.33	0.04
EM_ETANK_1	EM_ETANK_1	E_Additive 1	(11)	(11)	(11)
EM_ETANK_2	EM_ETANK_2	E_Additive 2	(11)	(11)	(11)
EM_ETANK_3	EM_ETANK_3	E_Additive 3	(11)	(11)	(11)
EM_ETANK_4	EM_ETANK_4	E_Additive 4	(11)	(11)	(11)
CAPTADD	CAPTADD	E_PE Additive Cap	VOC	0.93	<0.01
CPETANK_1	CPETANK_1	C_Seal Oil 1	(11)	(11)	(11)

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
CPETANK_2	CPETANK_2	C_Seal Oil 2	(11)	(11)	(11)
CPETANK_3	CPETANK_3	C_Seal Oil 3	(11)	(11)	(11)
CAPTSO	CAPTSO	C_PE Seal Oil Cap	VOC	<0.01	<0.01
CPETANK_4	CPETANK_4	C_Mineral Oil 1	(11)	(11)	(11)
CPETANK_5	CPETANK_5	C_Mineral Oil 2	(11)	(11)	(11)
CPETANK_6	CPETANK_6	C_Mineral Oil 3	(11)	(11)	(11)
CAPTMO	CAPTMO	C_PE Mineral Oil Cap	VOC	<0.01	<0.01
GTK-502A	GTK-502A	Glycol Day Tank 1	(11)	(11)	(11)
GTK-502B	GTK-502B	Glycol Day Tank 2	(11)	(11)	(11)
GTK-502C	GTK-502C	Glycol Rail and Truck Tank	(11)	(11)	(11)
CAPMEG	CAPMEG	Glycol Cap	VOC	2.73	0.29
GTK-401	GTK-401	Catalyst 1	VOC	0.32	<0.01
GD-408	GD-408	Catalyst 2	VOC	0.32	<0.01
GD-409	GD-409	Catalyst 3	VOC	0.04	<0.01
SCTOTE	SCTOTE	Spent Catalyst Tote	VOC	0.05	<0.01
GTK-501	GTK-501	Glycol Slop 1	VOC	0.91	0.03

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Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
ZTTK06	ZTTK06	Heavy Glycol Tank 1	(11)	(11)	(11)
ZTTK08T	ZTTK08T	Heavy Glycol Tank 2	(11)	(11)	(11)
CAPTHE	CAPTHE	Heavy Glycol Cap	VOC	1.82	<0.01
ZTTK07	ZTTK07	Glycol Bleed Tank 1	(11)	(11)	(11)
ZTTK09T	ZTTK09T	Glycol Bleed Tank 2	(11)	(11)	(11)
CAPTGB	CAPTGB	Glycol Bleed Cap	VOC	0.64	0.01
ZTTK03	ZTTK03	CPE Hexene	(11)	(11)	(11)
ZTTK04	ZTTK04	EM Hexene	(11)	(11)	(11)
CAPTHEX	CAPTHEX	Hexene Cap	VOC	1.58	4.03
ZTTK01	ZTTK01	Heavy Fuel Oil 1	(11)	(11)	(11)
ZTTK02	ZTTK02	Heavy Fuel Oil 2	(11)	(11)	(11)
CAPTHFO	CAPTHFO	Heavy Fuel Oil Cap	VOC	4.28	1.10
ZTTK11T	ZTTK11T	Slop Oil Tank 1	(11)	(11)	(11)
ZWTK17T	ZWTK17T	Slop Oil Tank 2	(11)	(11)	(11)
CAPTSLO	CAPTSLO	Slop Cap	VOC	1.50	3.58
ZWTK19	ZWTK19	WWTP Loading Spill Sump	(11)	(11)	(11)

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
ZWTK20	ZWTK20	WWTP Centrifuge Sump	(11)	(11)	(11)
ZTTK10	ZTTK10	OSBL Tankage Sump	(11)	(11)	(11)
ZFTK05	ZFTK05	Heat Exchanger Cleaning Sump	(11)	(11)	(11)
EM_ETANK_S	EM_ETANK_S	E_Sump	(11)	(11)	(11)
CPETANK_S	CPETANK_S	C_Sump	(11)	(11)	(11)
OTANK_S	OTANK_S	O_Sump	(11)	(11)	(11)
GTANK_S	GTANK_S	G_Sump	(11)	(11)	(11)
UTANK_S	UTANK_S	U_Sump	(11)	(11)	(11)
CAPTSUM	CAPTSUM	Sump Cap	VOC	4.36	0.09
ZWTK07	ZWTK07	Wastewater Slop Tank 1	(11)	(11)	(11)
ZWTK06	ZWTK06	Wastewater Slop Tank 2	(11)	(11)	(11)
CAPTWWSL	CAPTWWSL	WW Slop Cap	VOC	0.49	0.15
ZFTK02	ZFTK02	Diesel Firepump	(11)	(11)	(11)
ZMTK02	ZMTK02	Diesel Infrastructure	(11)	(11)	(11)
CAPTDSL	CAPTDSL	Diesel Cap	VOC	0.04	<0.01
TKUGEN1	TKUGEN1	Generator 1 Tank	(11)	(11)	(11)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
TKUGEN2	TKUGEN2	Generator 2 Tank	(11)	(11)	(11)
TKUGEN3	TKUGEN3	Generator 3 Tank	(11)	(11)	(11)
TKUGEN4	TKUGEN4	Generator 4 Tank	(11)	(11)	(11)
TKUGEN5	TKUGEN5	Generator 5 Tank	(11)	(11)	(11)
TKUFWP1	TKUFWP1	Firewater Pump Tank	(11)	(11)	(11)
TKGGEN6	TKGGEN6	Glycol Generator Tank	(11)	(11)	(11)
CAPEDSL	CAPEDSL	Engine Tank Cap	VOC	0.08	<0.01
ZMTK01	ZMTK01	Gasoline Infrastructure	(11)	(11)	(11)
ZFTK04	ZFTK04	Fire Training Gasoline	(11)	(11)	(11)
CAPTGAS	CAPTGAS	Gasoline Cap	VOC	11.57	1.78
TOTES	TOTES	Site totes	VOC	0.86	<0.01
INORG	INORG	Inorganic Chemicals Storage	H_2SO_4	<0.01	<0.01
INORG	INORG	Inorganic Chemicals Storage	NaOCl	0.29	<0.01
U_NH3SMP	U_NH3SMP	Ammonia Sump	(12)	(12)	(12)
U_NH3WW	U_NH3WW	Ammonia Wastewater Collection Vessel	(12)	(12)	(12)
U_NH3CAP	U_NH3CAP	Ammonia Handling Cap	NH_3	2.55	0.17

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR

Notes:

(1) Emissions from Furnaces A - H are listed in Olefins Furnaces Cap.

(2) Multi-point ground flare hourly limits are the sum of Intermittent and Continuous operation, and Elevated flare hourly limits are the sum of Intermittent and Continuous operation.

(3) Elevated and Ground Flare Cap is the sum of annual emissions from Elevated Flare and Ground Flare during all modes of operation. This cap does not include the Glycols Elevated Flare.

(4) Glycols Elevated Flare hourly limits are the sum of Intermittent or Continuous operation, and annual limits are the sum of all modes of operation.

(5) Emissions from Glycol vacuum vents are listed in Glycol Vaccum System Cap.

(6) Emissions from Boilers A, B, and C are listed in Utilities Boilers Cap.

(7) Emissions from Thermal Oxidizers A and B are listed in Shared Thermal Oxidizer Cap.

(8) Engine cap represents emissions from low-annual use site engines.

(9) Vents from both EPE and CPE Polyethlene Units are combined in PE Vents Cap.

(10) Fugitive emissions from both EPE and CPE Polyethylene Units are combined in PE Fugitives.

(11) Tank emissions capped.

(12) Emissions from Ammonia Sump and Ammonia Wastewater Collection Vessel are listed in Ammonia Handling Cap.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			4. UTM Coordinates of Emission Point			Source								
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives			
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
O_FAF01	O_FAF01	Furnace A	15	665046	3090378	10	190	8	50	282			
O_FBF01	O_FBF01	Furnace B	15	665054	3090392	10	190	8	50	282			
O_FCF01	O_FCF01	Furnace C	15	665063	3090407	10	190	8	50	282			
O_FDF01	O_FDF01	Furnace D	15	665072	3090422	10	190	8	50	282			
O_FEF01	O_FEF01	Furnace E	15	665082	3090441	10	190	8	50	282			
O_FFF01	O_FFF01	Furnace F	15	665091	3090457	10	190	8	50	282			
O_FGF01	O_FGF01	Furnace G	15	665099	3090471	10	190	8	50	282			
O_FHF01	O_FHF01	Furnace H	15	665108	3090486	10	190	8	50	282			
UFFLARE01	UFFLARE01	Multi-point Ground Flare	15	665369	3090502	10	TBD	TBD	TBD	TBD			
UFFLARE02	UFFLARE02	Shared Elevated Flare	15	665311	3090595	10	TBD	TBD	TBD	TBD			
O_FUG	O_FUG	Olefins Unit Fugitives	15	664859	3090542	10	20	0.003	0.003	ambient			
O_ACV	O_ACV	Olefins Regeneration Vent	15	664859	3090542	10	TBD	TBD	TBD	TBD			
GFFLARE03	GFFLARE03	Glycol Elevated Flare	15	664275	3090867	10	TBD	TBD	TBD	TBD			
GX202	GX202	Glycol Thermal Oxidizer	15	664350	3090800	10	TBD	TBD	TBD	TBD			
GD503A	GD503A	Glycol Vacuum Vent A	15	664540	3090726	10	20	0.003	0.003	ambient			
GD503B	GD503B	Glycol Vacuum Vent B	15	664540	3090726	10	20	0.003	0.003	ambient			
GD103	GD103	Glycol Moderator	15	664540	3090726	10	20	0.003	0.003	ambient			
GFUG	GFUG	Glycol Unit Fugitives	15	664540	3090726	10	20	0.003	0.003	ambient			
UCCT01	UCCT01	Utilities Cooling Tower	15	664744	3090856	10	TBD	TBD	TBD	TBD			
USSG01A	USSG01A	Utilities Boiler A	15	665195	3090600	10	150	10	54	350			
USSG01B	USSG01B	Utilities Boiler B	15	665185	3090584	10	150	10	54	350			
USSG01C	USSG01C	Utilities Boiler C	15	665175	3090565	10	150	10	54	350			
UFF01_A	UFF01_A	Shared Thermal Oxidizer A	15	665251	3090633	10	TBD	TBD	TBD	TBD			
UFF01_B	UFF01_B	Shared Thermal Oxidizer B	16	665220	3090651	10	TBD	TBD	TBD	TBD			
U_FUG	U_FUG	Utilities Fugitives	15	665028	3090718	10	10	0.003	0.003	ambient			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume I*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
U_GEN1	U_GEN1	Emergency Generator No. 1	15	664700	3090737	10	10	0.70	225	400			
U_GEN2	U_GEN2	Emergency Generator No. 2	15	664933	3090686	10	10	0.70	225	400			
U_GEN3	U_GEN3	Emergency Generator No. 3	15	664700	3090737	10	10	0.70	225	400			
U_GEN4	U_GEN4	Emergency Generator No. 4	15	665078	3090608	10	10	0.70	225	400			
U_GEN5	U_GEN5	Emergency Generator No. 5	15	665592	3090096	10	10	0.70	225	400			
U_FWP	U_FWP	Firewater Pump No. 1	15	664713	3090364	10	10	0.70	225	400			
G_GEN6	G_GEN6	Glycol Generator No. 1	15	664700	3090737	10	10	0.70	225	400			
U_LLOAD	U_LLOAD	Rail/Truck Liquid Loading	15	664838	3091174	10	10	0.003	0.003	ambient			
WWTP	WWTP	Wastewater System	15	664684	3090323	10	TBD	TBD	TBD	TBD			
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	15	664540	3090726	10	20	0.003	0.003	ambient			
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	15	664618	3090352	10	12	3	63	1400			
REFUSTN	REFUSTN	Vehicle Refueling Station	15	664621	3091002	10	10	0.003	0.003	ambient			
E_LLDS_001	ELLDS_001	Granular Feed bin transfer air Vent	15	665042	3091001	10	135	1	25	140			
E_DLDS_002	EDLDS_002	Product Purge bin Screener Dust Collector Vent	15	665042	3091001	10	40	1	56	140			
E_LLFB_001	ELLFB_001	Feed bin exit Dust collector Vent	15	665042	3091001	10	80	0	56	140			
E_DLSB_002	EDLSB_002	Seed bed bin Dust collector Vent	15	665042	3091001	10	30	0.33	30	ambient			
E_MEXT_001	EMEXT_001	Extruder Feed Hopper Vent	15	665042	3091001	10	18	0	88	140			
E_DLSB_001	EDLSB_001	Granule Filter Receiver (seed bed filter)	15	665042	3091001	10	135	2	30	ambient			
E_PLDS_006	EPLDS_006	Line 1 - Prime Pellet Silo Vent 01	15	665042	3091001	10	80	1	42	ambient			
E_PLDS_007	EPLDS_007	Line 1 - Prime Pellet Silo Vent 02	15	665042	3091001	10	80	1	42	ambient			
E_PLDS_008	EPLDS_008	Line 1 - Prime Pellet Silo Vent 03	15	665042	3091001	10	80	1	42	ambient			
E_PLDS_009	EPLDS_009	Line 1 - Prime Pellet Silo Vent 04	15	665042	3091001	10	80	1	42	ambient			
E_PLDS_010	EPLDS_010	Line 1 - Prime Pellet Silo Vent 05	15	665042	3091001	10	80	1	42	ambient			
E_MPPS_001	EMPPS_001	Line 1 - Pellet Surge Bin Vent	15	665042	3091001	10	32	0.50	37	ambient			
E_MPPS_002	EMPPS_002	Line 1 - Pellet Dryer Vent-01	15	665042	3091001	10	120	2	62	ambient			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

TCEQ

Table 1(a) Emission Point Summary - *Volume I*

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						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives			
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
E_MPPS_003	EMPPS_003	Line 1 - Pellet Dryer Vent-02	15	665042	3091001	10	120	2	62	ambient			
E_MPPX_001	EMPPX_001	Line 1 - Film Test Extruder Filter Receiver	15	665042	3091001	10	20	0.25	18	ambient			
E_LFBF_001	ELFBF_001	Finishing Building Vacuum System Dust Collector	15	665042	3091001	10	41	3	0.33	ambient			
E_LADD_001	ELADD_001	Line 1 Additive Feed Hopper Blower Vent	15	665042	3091001	10	50	0.50	42	ambient			
E_LADD_002	ELADD_002	Line 1 - Additive Drying Hopper Dust Collector	15	665042	3091001	10	50	0.50	5	ambient			
E_LADD_004	ELADD_004	Line 1 - Vacuum Blower-01 Vent for Additive AB Transfer	15	665042	3091001	10	50	1	13	ambient			
E_LADD_005	ELADD_005	Line 1 - Vacuum Blower-03 Vent for Additive Transfer	15	665042	3091001	10	50	1	13	ambient			
E_LADD_006	ELADD_006	Lines 1/2 - Vacuum Blower-04 Vent for Additive Transfer	15	665042	3091001	10	50	1	13	ambient			
E_LADD_004	ELADD_004	Line 1 - Vacuum Blower-01 Vent for Additive AB Transfer	15	665042	3091001	10	50	1	13	ambient			
E_BCTS_001	EBCTS_001	Line 1 - Cylinder Vent Filter-01	15	665042	3091001	10	20	0.50	7	ambient			
E_BCTS_002	EBCTS_002	Line 1 - Cylinder Vent Filter-02	15	665042	3091001	10	20	0.50	7	ambient			
E_BCTS_003	EBCTS_003	Line 1 - Cylinder Vent Filter-03	15	665042	3091001	10	20	0.50	7	ambient			
E_BCTS_004	EBCTS_004	Line 1 - Catalyst Hold Tank Filter-04	15	665042	3091001	10	82	0.50	10	ambient			
E_BCTS_005	EBCTS_005	Line 1 - Catalyst Hold Tank Filter-05	15	665042	3091001	10	82	0.50	10	ambient			
E_BCTS_006	EBCTS_006	Line 1A - Catalyst Hold Tank Filter-06	15	665042	3091001	10	82	0.50	10	ambient			
E_CR01	ECR01	Line 1 - Reactor startup Nitrogen transfer/purge Vent to ATM	15	665042	3091001	10	82	0	10	ambient			
E_FUG	E_FUG	EM PE Unit Fugitives	15	665042	3091001	10	20	0.003	0.003	ambient			
C_LLDS_001	CLLDS_001	Granular Feed bin transfer air Vent	15	665208	3090906	10	49	0.17	10	86			
C_DLDS_002	CDLDS_002	Product Purge bin Screener Dust Collector Vent	15	665208	3090906	10	49	0.17	10	86			
C_LLFB_001	CLLFB_001	Feed bin exit Dust collector Vent	15	665208	3090906	10	49	0.17	10	86			
C_DLSB_002	CDLSB_002	Seed bed bin Dust collector Vent	15	665208	3090906	10	49	0.17	10	86			
C_MEXT_001	CMEXT_001	Extruder Feed Hopper Vent	15	665208	3090906	10	49	0.17	10	86			
C_DLSB_001	CDLSB_001	Granule Filter Receiver (seed bed filter)	15	665208	3090906	10	49	0.17	10	86			
C_PLDS_006	CPLDS_006	Line 2 - Prime Pellet Silo Vent 01	15	665208	3090906	10	49	0.17	10	86			
C_PLDS_007	CPLDS_007	Line 2 - Prime Pellet Silo Vent 02	15	665208	3090906	10	49	0.17	50	86			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives			
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
C_PLDS_008	CPLDS_008	Line 2 - Prime Pellet Silo Vent 03	15	665208	3090906	10	49	0.17	30	86			
C_PLDS_009	CPLDS_009	Line 2 - Prime Pellet Silo Vent 04	15	665208	3090906	10	49	0.17	10	86			
C_PLDS_010	CPLDS_010	Line 2 - Prime Pellet Silo Vent 05	15	665208	3090906	10	49	0.17	10	86			
C_MPPS_001	CMPPS_001	Line 2 - Pellet Surge Bin Vent	15	665208	3090906	10	98	0.08	64	104			
C_MPPS_002	CMPPS_002	Line 2 - Pellet Dryer Vent-01	15	665208	3090906	10	98	0.08	64	104			
C_MPPS_003	CMPPS_003	Line 2 - Pellet Dryer Vent-02	15	665208	3090906	10	98	0.08	64	104			
C_MPPX_001	CMPPX_001	Line 2 - Film Test Extruder Filter Receiver	15	665208	3090906	10	98	0.08	64	104			
C_LFBF_001	CLFBF_001	Finishing Building Vacuum System Dust Collector	15	665208	3090906	10	98	0.08	64	104			
C_LADD_001	CLADD_001	Line 2 - Additive Feed Hopper Blower Vent	15	665208	3090906	10	98	0.08	64	104			
C_LADD_002	CLADD_002	Line 2 - Additive Drying Hopper Dust Collector	15	665208	3090906	10	43	0.09	3	86			
C_LADD_004	CLADD_004	Line 2 - Vacuum Blower-02 Vent for Additive AB Transfer	15	665208	3090906	10	43	0.25	30	86			
C_LADD_005	CLADD_005	Line 2 - Vacuum Blower-04 Vent for Additive Transfer	15	665208	3090906	10	43	0.09	3	86			
C_LADD_006	CLADD_006	Lines 2 - Vacuum Blower-06 Vent for Additive Transfer	15	665208	3090906	10	108	2	88	158			
C_LADD_004	CLADD_007	Line 2 - Additive Dump Station Vent Dust Collector	15	665208	3090906	10	43	0	50	86			
C_BCTS_001	CBCTS_001	Line 2 - Cylinder Vent Filter-01	15	665208	3090906	10	75	1	16	104			
C_BCTS_002	CBCTS_002	Line 2 - Cylinder Vent Filter-02	15	665208	3090906	10	20	1	4	ambient			
C_BCTS_003	CBCTS_003	Line 2 - Cylinder Vent Filter-03	15	665208	3090906	10	108	2	88	158			
C_BCTS_004	CBCTS_004	Line 2 - Catalyst Hold Tank Filter-04	15	665208	3090906	10	108	2	88	158			
C_BCTS_005	CBCTS_005	Line 2 - Catalyst Hold Tank Filter-05	15	665208	3090906	10	108	2	88	158			
C_BCTS_006	CBCTS_006	Line 2 - Catalyst Hold Tank Filter-06	15	665208	3090906	10	108	2	88	158			
C_CR01	CCR01	Line 2 - Reactor startup Nitrogen transfer/purge Vent to ATM	15	665208	3090906	10	108	2	88	158			
PE_REGEN	PE_REGEN	PE Treater Regeneration	15	665208	3090906	10	108	2	88	158			
C_FUG	C_FUG	CPE PE Unit Fugitives	15	665208	3090906	10	20	0.003	0.003	ambient			
UTTK101T	UTTK101T	Pygas Day Tank 1	15	664859	3090542	10	30	0.003	0.003	ambient			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
UTTK102T	UTTK102T	Pygas Day Tank 2	15	664859	3090542	10	30	0.003	0.003	ambient			
UTTK103T	UTTK103T	Sulfidic Caustic Day Tank 1	15	664859	3090542	10	20	0.003	0.003	ambient			
UTTK104T	UTTK104T	Sulfidic Caustic Day Tank 2	15	664859	3090542	10	20	0.003	0.003	ambient			
UTTK107T	UTTK107T	Light Oil Tank	15	664859	3090542	10	10	0.003	0.003	ambient			
UTTK100T	UTTK100T	Diesel Day Tank 1	15	664859	3090542	10	10	0.003	0.003	ambient			
EM_ETANK_1	EM_ETANK_1	E_Additive 1	15	665042	3091001	10	5	0.003	0.003	ambient			
EM_ETANK_2	EM_ETANK_2	E_Additive 2	15	665042	3091001	10	5	0.003	0.003	ambient			
EM_ETANK_2	EM_ETANK_2	E_Additive 3	16	665042	3091001	10	5	0.003	0.003	ambient			
EM_ETANK_2	EM_ETANK_2	E_Additive 4	17	665042	3091001	10	5	0.003	0.003	ambient			
CPETANK_1	CPETANK_1	C_Seal Oil 1	15	665208	3090906	10	13	0.003	0.003	ambient			
CPETANK_2	CPETANK_2	C_Seal Oil 2	15	665208	3090906	10	13	0.003	0.003	ambient			
CPETANK_3	CPETANK_3	C_Seal Oil 3	15	665208	3090906	10	13	0.003	0.003	ambient			
CPETANK_4	CPETANK_4	C_Mineral Oil 1	15	665208	3090906	10	7	0.003	0.003	ambient			
CPETANK_5	CPETANK_5	C_Mineral Oil 2	15	665208	3090906	10	7	0.003	0.003	ambient			
CPETANK_6	CPETANK_6	C_Mineral Oil 3	15	665208	3090906	10	7	0.003	0.003	ambient			
GTK-502A	GTK-502A	Glycol Day Tank 1	15	664489	3090870	10	40	0.003	0.003	ambient			
GTK-502B	GTK-502B	Glycol Day Tank 2	15	664508	3090859	10	40	0.003	0.003	ambient			
GTK-401	GTK-401	Catalyst 1	15	664540	3090726	10	11	0.003	0.003	ambient			
GD-408	GD-408	Catalyst 2	15	664540	3090726	10	11	0.003	0.003	ambient			
GD-409	GD-409	Catalyst 3	15	664540	3090726	10	8	0.003	0.003	ambient			
SCTOTE	SCTOTE	Spent Catalyst Tote	15	664540	3090726	10	4	0.003	0.003	ambient			
GTK-501	GTK-501	Glycol Slop 1	15	664540	3090726	10	40	0.003	0.003	ambient			
ZTTK06	ZTTK06	Heavy Glycol Tank 1	15	664816	3091057	10	36	0.003	0.003	ambient			
ZTTK08T	ZTTK08T	Heavy Glycol Tank 2	15	664816	3091057	10	36	0.003	0.003	ambient			
ZTTK07	ZTTK07	Glycol Bleed Tank 1	15	664727	3091060	10	39	0.003	0.003	ambient			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
ZTTK09T	ZTTK09T	Glycol Bleed Tank 2	15	664727	3091060	10	40	0.003	0.003	ambient			
ZTTK03	ZTTK03	CPE Hexene	15	664751	3091046	10	40	0.003	0.003	ambient			
ZTTK04	ZTTK04	EM Hexene	15	664864	3091028	10	40	0.003	0.003	ambient			
GTK-502C	GTK-502C	Glycol Rail and Truck Tank	15	664540	3090726	10	40	0.003	0.003	ambient			
ZTTK01	ZTTK01	Heavy Fuel Oil 1	15	664847	3091056	10	36	0.003	0.003	ambient			
ZTTK02	ZTTK02	Heavy Fuel Oil 2	15	664837	3091041	10	36	0.003	0.003	ambient			
ZTTK11T	ZTTK11T	Slop Oil Tank 1	15	664697	3091074	10	30	0.003	0.003	ambient			
ZWTK17T	ZWTK17T	Slop Oil Tank 2	15	664697	3091074	10	40	0.003	0.003	ambient			
ZWTK19	ZWTK19	WWTP Loading Spill Sump	15	664684	3090323	10	4	0.003	0.003	ambient			
ZWTK20	ZWTK20	WWTP Centrifuge Sump	16	664684	3090323	10	4	0.003	0.003	ambient			
ZTTK10	ZTTK10	OSBL Tankage Sump	17	664838	3091174	10	4	0.003	0.003	ambient			
ZFTK05	ZFTK05	Heat Exchanger Cleaning Sump	18	664792	3090890	10	4	0.003	0.003	ambient			
EM_ETANK_S	EM_ETANK_S	E_Sump	15	665042	3091001	10	4	0.003	0.003	ambient			
CPETANK_S	CPETANK_S	C_Sump	15	665208	3090906	10	4	0.003	0.003	ambient			
O_ETANK_S	O_ETANK_S	O_Sump	15	664859	3090542	10	4	0.003	0.003	ambient			
GTANK_S	GTANK_S	G_Sump	15	664816	3091057	10	4	0.003	0.003	ambient			
UTANK_S	UTANK_S	U_Sump	15	664792	3090890	10	4	0.003	0.003	ambient			
ZWTK07	ZWTK07	Wastewater Slop Tank 1	15	664618	3090363	10	30	0.003	0.003	ambient			
ZWTK06	ZWTK06	Wastewater Slop Tank 2	15	664618	3090363	10	16	0.003	0.003	ambient			
ZFTK02	ZFTK02	Diesel Firepump	15	664621	3091002	10	8	0.003	0.003	ambient			
ZMTK02	ZMTK02	Diesel Infrastructure	15	664646	3091130	10	25	0.003	0.003	ambient			
TKUGEN1	TKUGEN1	Generator 1 Tank	15	664697	3090740	10	3	0.003	0.003	ambient			
TKUGEN2	TKUGEN2	Generator 2 Tank	15	664936	3090685	10	3	0.003	0.003	ambient			
TKUGEN3	TKUGEN3	Generator 3 Tank	15	664697	3090740	10	3	0.003	0.003	ambient			
TKUGEN4	TKUGEN4	Generator 4 Tank	15	665082	3090607	10	3	0.003	0.003	ambient			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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TKUGEN5	TKUGEN5	Generator 5 Tank	15	665588	3090099	10	3	0.003	0.003	ambient				
TKUFWP1	TKUFWP1	Firewater Pump Tank	15	664719	3090363	10	3	0.003	0.003	ambient				
TKGGEN6	TKGGEN6	Glycol Generator Tank	15	664697	3090740	10	3	0.003	0.003	ambient				
ZMTK01	ZMTK01	Gasoline Infrastructure	15	664646	3091130	10	25	0.003	0.003	ambient				
ZFTK04	ZFTK04	Fire Training Gasoline	15	664621	3091002	10	8	0.003	0.003	ambient				
U_NH3SMP	U_NH3SMP	Ammonia sump	15	664859	3090542	10	4	0.003	0.003	ambient				
U_NH3WW	U_NH3WW	Ammonia Wastewater Collection Vessel	15	664489	3090870	10	4	0.003	0.003	ambient				

EPN = Emission Point Number
FIN = Facility Identification Number

TCEQ

TABLE 1F
AIR QUALITY APPLICATION SUPPLEMENT

Permit No.: **TBD**		Application Submittal Date: **April 2017**							
Company: **GCGV Asset Holding LLC**									
RN: **TBD**	Facility Location: **Near Gregory**								
City: **Near Gregory**	County: **San Patricio**								
Permit Unit I.D.:	Permit Name: **GCGV**								
Permit Activity:	✓ New Source Modification								
Complete for all Pollutants with a Project Emission Increase.	**POLLUTANTS**								
	Ozone								
	VOC	**NO_x**	**CO**	**PM_{10}**	**$PM_{2.5}$**	**NO_X**	**SO_2**	**CO_2e**[1]	
Nonattainment?	NO	NO	NO	NO	NO	NO	NO	NO	
PSD?	YES	YES	YES	YES	YES	YES	NO	NO	
Existing site PTE (tpy)?	--	--	--	--	--	--	--	--	
Proposed project emission increases (tpy from 2F[2])?	917.79	505.14	1,346.07	175.08	166.24	505.14	37.71	2,984,219	
Is the existing site a major source?	NO	NO	NO	NO	NO	NO	NO	NO	
If not, is the project a major source by itself?	YES	YES	YES	YES	YES	YES	NO	YES	
If site is major source, is project increase significant?	YES	YES	YES	YES	YES	YES	--	YES	
If netting required, estimated start of construction: --									
5 years prior to start of construction contemporaneous: --									
Estimated start of operation period: --									
Net contemporaneous change, including proposed project, from Table 3F. (tpy)	--	--	--	--	--	--	--	--	
Major NSR Applicable?	YES	YES	YES	YES	YES	YES	NO	YES	

WH Clark President 4/12/17

Signature *Title* *Date*

[1] Other pollutants. [Pb, H_2S, TRS, H_2SO_4, Fluoride excluding HF, etc.]

[2] Sum of proposed emissions minus baseline emissions, increases only.

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

SECTION 2
INTRODUCTION

This application is submitted to authorize construction of a grassroots olefin and derivatives manufacturing complex which is envisioned to be a 50:50 Joint Venture [between ExxonMobil Chemical Company (ExxonMobil) and Saudi Basic Industries Corporation (SABIC)] called Gulf Coast Growth Ventures Project (GCGV). The company is **GCGV Asset Holding LLC.**

2.1 Site Information

The project will include a process unit used to convert market pipeline ethane to olefins ("the Olefins unit") and multiple process units which will receive the ethylene, produced in the Olefins unit, as feed.

The olefins, derivatives, utilities, and infrastructure areas will be owned by GCGV. The derivatives units include two polyethylene units ("EPE", "CPE" or collectively "PE") and a Glycol unit ("the Glycol unit").

The utilities and infrastucture on-site support facilties include steam, rail, cooling water,liquid transport, and wastewater treatment. Finished polyethylene from the process units will be loaded at a rail transfer station ("the rail yard") potentially owned and operated by a third party. The Olefins, Glycol, EPE, and CPE process units and utilities will be enclosed by an inner fenceline. Liquid loading and unloading will occur at truck, rail, and transfer stations operated by the GCGV within the inner fenceline. The units will receive oxygen, compressed air, and nitrogen from an Air Separation Unit ("the ASU") owned and operated by a third party potentially located within the outer fenceline. A single controlled access outer fenceline will enclose GCGV process units/utilities/infrastructure, a third party air separation unit, and a railyard which is potentially third party. These process units, support units, and land loading facilities are collectively recognized in this application. A site layout for the proposed facilities is detailed in the plot plan included in the confidential appendices.

Units at the site will be sized for world-scale production which can be anticipated to impart significant regional and local economic gains. The project will create numerous permanent jobs and provide abundant contracting opportunities during construction and operation phases. Locating the project in the U.S. Gulf Coast allows access to an abundant supply of affordable feedstock and energy, manufacturing and export infrastructure and a highly trained workforce. It could generate more than $22 billion in economic output during the construction phase and $50+ billion in economic output during the first six years of operations. In addition to these induced economic benefits to the community, the project will result in an expanded tax base to support government.

The site will be located near Gregory in San Patricio County, Texas. Air-related permitting and reporting activities by the site will be tracked under new Account, Regulated Entity, and Customer Reference Nos. assigned by the Texas Commission on Environmental Quality. It is anticipated that the site will request separate CNs for the Rail Yard, ASU, and GCGV.

Figure 2-1 included at the end of this section presents an area map showing the location of the site to nearby topographic features. The site will be located south of Highway 181 and west of FM2986. The total property comprises an area of approximately 1,300 acres currently used for primarily agricultural purposes. Surrounding property is mixed residential and agricultural to the east and southeast, and agricultural on all other sides.

2.2 Permitting Overview

This application is for a New Source Review (NSR) Air Quality Permit under Title 30 Texas Administrative Code (TAC) Chapter 116, Subchapter B for the following process units/activities which will result in air emissions:

- The Olefins unit;
- The Polyethylene units;
- The Glycol unit;
- Liquids loading at the railyard;
- Utility support facilities; and
- Maintenance, Startup, and Shutdown (MSS) activities identified in the proposed caps.

Not included above are the ASU and some railyard operations. These third party areas of the site will be authorized in separate actions, but will not be excluded from any analysis required of this project review.

2.3 Federal NSR Applicability Review

San Patricio County is currently classified as unclassified/attainment status for all criteria pollutants. Prevention of Significant Deterioration (PSD) Review applies to new sources with the potential to emit pollutants above named or unnamed major source thresholds. The facility is a chemical process plant, which is a named source in the PSD regulations. At least one pollutant is above the named PSD Major Source emission rate of 100 tpy. The potential to emit (PTE) of new sources is compared to the significant emission rate thresholds below:

Table 2-1 Project Emissions

Pollutant	PTE TPY	Significant Emission Rate TPY	Is Netting Triggered? Y/N	Net Increase TPY	Is FNSR Applicable? Y/N
NOx	505.14	40	N	na	Y
CO	1,346.07	100	N	na	Y
VOC	917.79	40	N	na	Y
SO_2	37.71	40	N	na	N
H_2SO_4	1.04	7	N	na	N
PM	184.55	25	N	na	Y
PM_{10}	175.08	15	N	na	Y
$PM_{2.5}$	166.24	10	N	na	Y

PSD review applies to NOx, CO, VOC, PM, PM_{10}, and $PM_{2.5}$ because the PTE of these pollutants is over the significant emission rate for these pollutants. There are no upstream/downstream effects to consider as this is a new facility and all emission sources are accounted for in the facility's PTE. Minor NSR review applies to SO_2 and H_2SO_4.

2.4 Federal NSR Applicability Review for GHG

The PTE of CO_2 equivalents (CO_2e) [carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O)] are calculated in this application and compared to the "anyway" major source level of 75,000 tpy CO_2e because the application is subject to PSD Best Available Control Technology (BACT) Review for other pollutants.

Table 2-2 Project GHG Emissions

Pollutant	PTE TPY	Major Source Rate TPY	Is Netting Triggered? Y/N	Net Increase TPY	Is FNSR Applicable? Y/N
CO_2e	2,984,219	75,000	N	N/A	Y

The project triggers GHG PSD BACT Review because it triggers PSD Review for other pollutants and has a PTE of 2,984,219 tpy CO_2e. The Table 1(a) for GHG, as well as a discussion of GHG emissions calculations and an analysis of GHG BACT are provided in Volume II of this application.

2.5 Application Overview

This document constitutes a complete NSR permit application per 30 TAC Chapter 116 and 40 CFR Part 52. Key components of a complete application are included in this document as follows:

- TCEQ administrative forms and associated documents are included in Section 1;
- An area map is provided in Section 2;
- A non-confidential process description is provided in Section 3;
- Emission calculation methods for non-GHG pollutants from each source type are discussed in Section 4 of Volume I;
- Emission calculation methods for GHG pollutants from each source type are discussed in Section 4 of Volume II;
- A review of Best Available Control Technology (BACT) for non-GHG pollutants is provided in Section 5;
- GHG BACT analysis is provided in Section 6 of Volume II;
- Considerations for Granting a Permit, including discussions of applicable regulations and compliance methods, are contained in Section 7; and
- Appendix A contains the plot plan, process flow diagrams, equipment tables, and emission calculations for sources associated with this project, which are considered confidential business information.
  - Any request for portions of this application that are marked as confidential must be submitted in writing, pursuant to the Public Information Act, to the TCEQ Public Information Coordinator, MS 197, P.O. Box 13087, Austin, Texas 78711-3087.

2.6 Application Fee

The permit application fee is submitted concurrently with the permit application for this project under separate cover. A copy of the check is included in Section 1 of this application.

SAGE ATC ENVIRONMENTAL CONSULTING	PSD Air Permit Initial Application	FIGURE 2-1 **Area Map** GCGV Project
	April 2017	
	400 – 55 – 25	

SECTION 3
PROCESS DESCRIPTION

An overview of each chemical manufacturing process at the proposed facilty is provided below. A General Flow Diagram showing the facility's production units and main control devices is provided at the end of this section.

3.1 Olefins Production

The proposed project includes construction of a new olefins production unit. The unit will include eight (8) new steam cracking furnaces, recovery equipment, utilities, refrigeration, cooling, and treatment systems. The major pieces of recovery equipment include the quench circuit, cracked gas compression, acid gas removal, chilling train, and fractionation sections.

The new unit will process hydrocarbon feedstocks to produce ethylene and other products.

Fresh ethane feed to the unit is superheated and combined with residual ethane from the recovery section. A small amount of crackable sulfur such as dimethyl sulfide (DMS) is added to the mixed hydrocarbon feed to reduce furnace radiant tube coking rate. The mixed stream of hydrocarbons is fed to the cracking section of the unit.

The cracking section consists of 8 furnaces of proprietary design. The hydrocarbon feed is mixed with the dilution steam and preheated in the furnace convection section. The preheated mixed feed then enters the furnace radiant section and starts thermal decomposition pyrolysis reactions. The furnace effluent consists of light olefins (ethylene, propylene, butadiene, etc.), byproducts, un-reacted feedstock, and steam. The furnace effluent is cooled in a series of transfer line exchangers (TLE) that produce high pressure steam and preheat the furnace feed. Furnaces periodically require decoking. Decoking the furnace tubes will be accomplished by routing the decoke stream to the furnace combustion section.

The energy required for the pyrolysis reaction is generated via the combustion of blend gas (tail gas, as described below, and natural gas) in a series of burners installed in the furnace radiant section. Tail gas is a recycle stream of predominately methane and hydrogen that is generated in the chilling train and fractionation area of the recovery section. Tail gas is mixed with natural gas for a furnace and boiler fuel referred to as "blend gas" in this application. Ethane may be used as a backup to natural gas during brief natural gas unavailability. The furnace burners are capable of firing natural gas or blend gas.

The cooled furnace effluent is fed to the quench system, where a majority of the dilution steam and heavier hydrocarbons are condensed. The condensed water is subsequently cleaned, stripped of residual hydrocarbon, and re-used to generate the dilution steam that is used in the furnaces. The heavy hydrocarbon is processed to a pyrolysis gasoline and fuel oil product. The cooled cracked gas is sent to the cracked gas compression section.

To fractionate the furnace effluent, the cracked gas is compressed in a multi-stage compressor driven by a steam turbine. The compressed gas is then treated to remove acid gas (e.g. CO_2 and H_2S) by reacting them with caustic (NaOH) into soluble compounds.

The cracked gas leaving the caustic wash system is cooled to knock out water and sent to dryers to remove any remaining water. Drying of the cracked gas is necessary to prevent hydrate formation in the chilling section of the unit. The dryers will be regenerated periodically in situ using tail gas.

The chilled cracked gas is then fed to the deethanizer to separate ethane and lighter gas from C3 and heavier components. The C3 and heavier components are fed to the coproducts processing area. The acetylene reactors in the coproduct section will need to be regenerated periodically. The regeneration process will be done in situ with a portion of the regeneration vented to atmosphere. The C3 and C4 streams can be recycled to the feed preparation section and used as unit feed.

The light hydrocarbon stream from the overhead of the deethanizer is fed to the acetylene reactor system to selectively hydrogenate acetylene in the gas. The cold ends acetylene reactor will not be regenerated on-site.

After acetylene hydrogenation, the gas is cooled in the chill train for the subsequent separation of tail gas from the mixed C2s. This process is done through a series of equipment which recuperates the refrigeration potential of the gas. The mixed C2 stream is fed to the C2 splitter that fractionates the ethylene product from the ethane. The ethylene product is compressed and sent to the derivative units (Glycol and Polyethylene) as feedstock or routed to the ethylene grid. The ethylene compressor is driven by a steam turbine and also provides refrigeration for the unit. The ethane stream is recycled to the feed preparation section to be used as feed to the unit. Both the ethylene and ethane streams are heat integrated with other parts of the unit.

The unit will also include a dedicated propylene refrigeration system driven by steam turbine. This refrigeration system will provide the remaining refrigeration requirement that cannot be filled by the heat integration of the tail gas, ethylene, and ethane streams.

3.2 Polyethylene Production

There will be two polyethylene process units at the facility, both of which will produce Linear Low Density PE grades. The major pieces of equipment include feed purification beds, catalyst feeders, reactors, purge vessels, screw conveyers, extruders, silos, bins, hoppers, blow tanks, compressors, refrigeration equipment, storage silos and packaging lines.

The units will receive ethylene feed produced on-site and via an ethylene grid.

The reaction of gases involves polymerization, which is the linking or bonding of molecules to produce the polymer. Transition metal complex molecules and metal alkyls are impregnated onto catalyst support particles similar to fine sand. Catalyst is measured and conveyed into the reactor with an inert gas. The catalyst initiates the reaction of monomer (ethylene) and co-monomers in the reactor. Potential trace components that may impact the polymerization process are removed from reactor feed streams in the purification area. This purification process takes place in packed bed vessels. Non-reactive components are used to control catalyst activity and/or act as a heat removal medium. The polymer produced in the reactor is in the form of granules suspended by circulating gases used to remove heat. As different co-monomers and/or catalysts are needed to produce a different grade/type of polyethylene, the reactor is purged to the vent gas system during shutdowns, startups, and product grade transitions, where the ground flare, elevated flare, and thermal oxidizer provide control.

The polymer particles in the circulating gas form a fluidized bed in the reactor. Granular polyethylene is periodically removed through a series of tanks, along with entrained gas.

Unreacted gases are removed from the gas/resin stream leaving the reactor by degassing purge vessels that strip the gas from polyethylene product using an inert gas. Stripped gases are recovered with a unit recovery system. The unrecovered residual mixed hydrocarbon/inert gases are routed through a system where this vent is primarily routed to facility boilers. A thermal oxidizer, an elevated flare, and/or a multi-point ground flare serve as backup control for this vent. A small amount of residual hydrocarbon remains in the resin after purging.

Granular resin is air-conveyed from the purger area into silos (feed bins). Bag and other type of filters or cyclones are used on the solids handling equipment, including bin vents to control particulate emissions. The extruder uses mechanical work to melt the plastic and push it through a die-plate containing small holes. Various additives are added to impart certain physical characteristics to PE (such as anti-block, slip) as well as to protect the PE from degradation with temperature and oxygen. The plastic extrudes through these holes into spaghetti-like strands. The strands are cut with a series of rotating knives into small pieces known as pellets. These pellets are then conveyed into product silos. The material is air conveyed from the product silos to loadout. The product silos and load out stations are equipped with filters and/or cyclones to minimize the emission of particles to the atmosphere.

3.3 Glycol Production

The Ethylene Oxide (EO) Reaction System converts ethylene and oxygen across a silver-based catalyst in the EO reactors to produce ethylene oxide and byproduct carbon dioxide (CO_2).

Heat produced in the EO reactor is removed by boiler feed water (BFW) in the EO reactor shell side; the steam produced is used as a heat source in various areas of the process.

Ethylene oxide produced in the EO reaction system is recovered by contacting the EO reaction cycle gas with cool water, which preferentially absorbs the EO. An EO/water mixture is taken as an overhead liquid from the EO Stripper. EO Stripper overhead gases are recycled by the residual gas compressor back to EO reactor.

Low levels of argon present in the oxygen feed must be continuously purged from the EO reaction system to prevent build-up; an ethylene recovery unit is used to minimize the loss of ethylene in the argon purge stream. Subsequently, the argon purge stream is sent to a control device for the hydrocarbon in this stream.

The EO/water stream leaving the EO Stripper is converted to Monoethylene Glycol (MEG) in two reaction steps. The first step is the conversion of EO with dissolved CO2 to ethylene carbonate (EC). The second step is the reaction of EC with water to make MEG. The glycol/water mixture from the final reactor is taken to a Glycol Dehydrator to remove excess water.

The dewatered glycol stream and a heavy glycol stream collected in the EO section is routed to a series of vacuum distillation towers which separate the MEG from heavier Glycol. These streams are sent to product storage tanks.Glycol products (MEG, heavy Glycol), and glycol bleed produced by the unit will be loaded out at the facility's truck/rail transfer racks, or transferred by pipeline to a near-by marine terminal.

The Glycol vent gas system is separate from the shared system for the Olefins, Polyethylene, and Utilities and Infrastructure areas. The Glycol process vent gas system consists of a thermal oxidizer and an elevated flare. The ethylene oxide reactor produces CO_2 as a byproduct. The CO_2 byproduct is routed to the thermal oxidizer to control residual VOC emissions. The argon purge stream is routed to the burner of the thermal oxidizer to reduce the amount of supplemental fuel required in the thermal oxidizer. The Glycol elevated flare is the backup control for thermal oxidizer streams that require VOC control and receives various streams that occur during maintenance, startup, and shutdown and routine operations like pilot gas, sweep gas, purge gas, valve leakage, and some analyzer vents.

3.4 Utilities & Infrastructure

The process units will use common on-site utilities and infrastructure such as electricity, water, steam, nitrogen, plant air, feed, fuel, storage, loading and unloading, vent gas systems, and wastewater collection and treatment. Areas with emission sources include boilers for steam generation, cooling tower, tanks, loading/unloading operations, vent gas systems, and a wastewater treatment plant.

Steam production will be provided for the facility from boilers and furnaces. The boilers will fire natural gas, tail gas, ethane, and/or process gas. The steam system will include the boilers, condensate system, and boiler feed water system. The condensate from the system will be polished and processed to be used to make the steam in the furnaces and boilers.

Several new storage tanks will be constructed which will provide storage for materials such as ammonia, wash oil, lube oil, caustic, sulfidic caustic, sulfuric acid, methanol, and various water and process additives.

Pyrolysis gasoline, fuel oil, slop oil, sulfidic caustic, various glycol products, C3s, and C4s will be loaded at the facility's truck/rail transfer racks, or transferred by pipeline to a nearby marine terminal.

Cool water will be provided by a facility cooling tower to the process heat exchangers. The hot water is returned to the cooling tower where it cools before being pumped to the process unit heat exchangers. The cooling tower has a blowdown stream sent to the wastewater pond prior to leaving the facility.

The project will include systems to collect rain water and process wastewater. Rainwater and other pad water such as fire-fighting water is collected in sumps located in the Olefins, Glyol, and Utilities and Infrastructure areas. The system is designed to collect a first-flush of pad water then allow additional clean water to overflow to perimeter ditches. The containment of the first-flush water is used to prevent contamination of clean water outfall with particulates, lubrication oil, grease, or other contaminants that may be washed from equipment surfaces or other sources in the process pad area. Clean rainwater will be discharged into the storm water ditches.

Process wastewater generated in the Olefins, Glycol and miscellaneous Utilities and Infrastructure units will be gathered via the sewer system to an on-site wastewater treatment plant. Polyethylene first flush rain water and process water will be collected in the wastewater pond. Certain wastewater streams that contain benzene will be routed to a steam stripper to remove benzene from wastewater prior to treatment plant influent. The influent will flow through equalization tanks to stabilize chemical and hydraulic characteristics, dissolved air/gas flotation units to remove solids, a biological oxidation treatment basin to break down organics, and polishing clarifiers prior to pond holdup. Sludge from the clarifiers will be returned to the biological oxidation treatment basin to improve organics removal, and sludge and solids from the dissolved air/gas floatation unit will be dewatered.

Process vent gases are generated in the process units from the Olefins, Polyethylene, and various Utilities and Infrastructure activities. The facility has internal recycles to recover usable hydrocarbon molecules; however, there are vents that are useful for fuel or need control. The vent gas system routes the vents to boilers, thermal oxidizers, an elevated flare, and a ground flare. Vent gas dispositions within the system are based on flow rate, pressure, heating value, inerts content, frequency of generation, and speciation to optimize the system. GCGV takes advantage of vent gas stream properties while maintaining reliable operations and minimizing the need for supplemental fuel.

Vent streams routed to the boiler reduce the natural gas usage in the boilers. The boilers are essential for reliable Olefins operation and therefore utilize streams that are continuous, have a sufficient heating value, are low in fouling precursors (e.g. olefin content), and of adequate pressure. The boiler will be specifically designed to enable the use of vent gas while maintaining reliable operation.

The flare system is used for maintenance, startup, shutdown, and emergencies. Continuous streams to the flare will include pilot gas, sweep gas, and purge gas. Intermittent activities with high flows and high heating value, such as reactor and treatment bed depressurizations, are routed to the flare. Each of these intermittent depressurization activities typically occurs for a few hours per event. Some streams have low heating values and are routed to the thermal oxidizer to minimize the amount of supplemental fuel required to ensure good combustion compared to the flare. The thermal oxidizer vent gas streams are generally low flow, low pressure, or low heating value such as tank vents. The flare system also serves as the backup control device for process vent gas streams normally routed to the boiler and the thermal oxidizer.

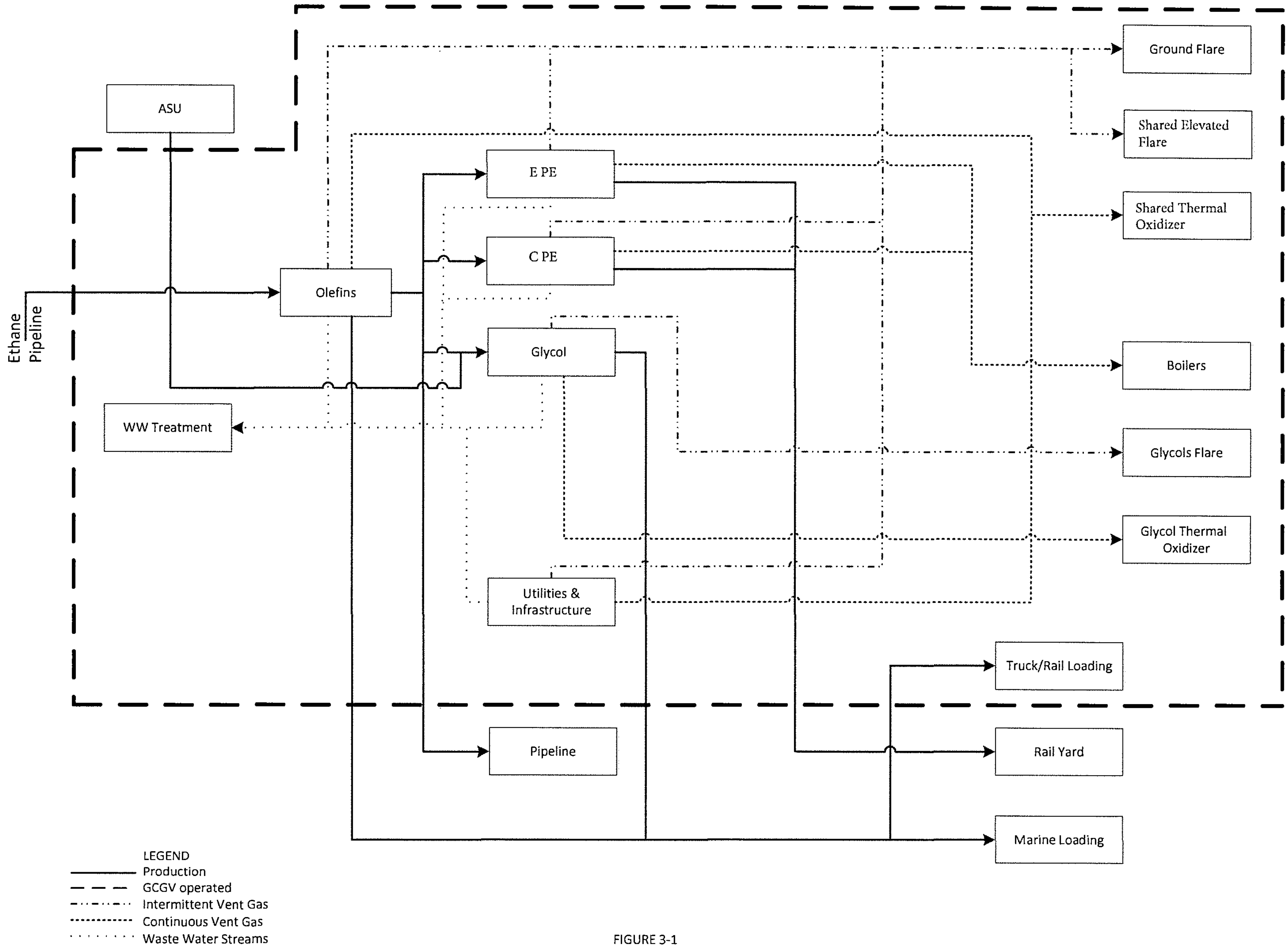

FIGURE 3-1
SIMPLIFIED PROCESS FLOW DIAGRAM
GCGV

SECTION 4
CALCULATION METHODOLOGY DISCUSSION

The project will result in emissions of the following pollutants: NOx, CO, VOC, PM, PM_{10}, $PM_{2.5}$, SO_2, H_2SO_4, NH_3, other inorganics, and CO_2e. The potential-to-emit (PTE) of each of these pollutants for the sources covered in this application was estimated using commonly accepted engineering principles and established emission factors. Provided below is a general description of each emission calculation. See Volume II for a discussion of CO_2e emission calculations. Detailed calculations are documented in the tables in Confidential Appendix A.3.

4.1 Boilers

4.1.1 VOC

The VOC factor of 5.50 lb/MMscf in AP-42, Fifth Edition, Volume 1 Section 1.4 "Natural Gas Combustion" was used to estimate unburned VOC emissions from natural gas and vent gas combustion in the Utility boilers. The factor was converted from a million standard cubic feet basis to a million British Thermal Units basis using natural gas and vent gas properties. Design heat input, the emission factor, and continuous utilization was used for each of the boilers to determine a mass emission rate.

The cap was calculated as the sum of the individual boiler rates. Based on performance of similar units and that the emission factor only accounts for VOC emissions from natural gas combustion, the annual emissions were adjusted downward by the hydrogen content of the projected average fuel composition.

4.1.2 NOx

Emissions were estimated using lb/MMBtu factors, max heat input, continuous utilization and summation of units in the cap for the cap rate. The annual emission rate is based on a performance of 0.01 lb/MMBtu SCR performance for all three boilers, while the worst-case hourly emission rate is based on the three boilers averaging 0.015 lb/MMBtu per hour .

4.1.3 CO

Emissions were estimated using performance factors of 100 ppmv hourly average stack concentration, 50 ppmv annual average stack concentration, max heat input, continuous utilization and summation of units in the cap for the cap rate. The stack concentration was converted to a heat input basis using typical natural gas and vent gas properties for hourly and typical blend gas and vent gas properties for annual.

4.1.4 SO_2

Emissions were calculated using the same methodology as VOC with the AP-42 factor of 0.60 lb/MMscf for SO_2.

4.1.5 $PM/PM_{10}/PM_{2.5}$

Emissions were calculated using the same methodology as VOC with the AP-42 factor of 7.60 lb/MMscf for Total PM (condensable and filterable portions). PM_{10} and $PM_{2.5}$ were set equal to Total PM.

4.1.6 NH_3

Emissions were calculated using the same methodology as CO with an SCR slip performance of 15 ppmv hourly average stack concentration and 10 ppmv annual average stack concentration for NH_3.

4.2 Cooling Tower

4.2.1 VOC

Because leak detection requirements in TCEQ Special Conditions will require Delay of Repair (DOR) recordkeeping and action level values at specific VOC concentrations in the return water, these values (0.8 ppmw hourly basis and 0.08 ppmw annual basis) are used in conjunction with the design circulation rate of the cooling tower to calculate, respectively, annual and hourly VOC rates.

4.2.2 $PM/PM_{10}/PM_{2.5}$

Emissions of Total PM were estimated using design circulation and drift elimination rates, as well as a worst-case Total Dissolved Solids (TDS) value for the water. Emissions of fine particulates (PM_{10}, $PM_{2.5}$) are not expected to be equal to Total PM. The cooling tower is an induced draft counter-current unit similar to other cooling towers which have been permitted under fine particulate speciations which rely on the Reisman-Frisbee correlation; however, to create a more conservative basis this application uses speciation factors that were developed by the South Coast Air Quality Management District (SCAQMD) for similar sources and are used by regulated entities in emissions reporting under SCAQMD purview.

4.3 Elevated Flares

4.3.1 VOC

A Destruction and Removal Efficiency (DRE) of 99% was used for straight-chained organic compounds consisting of three carbons and less and 98% for other compounds. The component-specific DRE was used in conjunction with projected vent gas component flows to determine component emissions, and VOC emissions were calculated as the sum of components considered VOCs.

4.3.2 NOx

Projected vent gas component compositions and flow were used in conjunction with standard reference Lower Heating Values (LHVs) for the components to determine a heat release for the vent gas. The heat release was used in conjunction with factors in TCEQ RG-109 specific to the assist-type and low or high Btu content of the stream specific to each flare.

4.3.3 CO

Emissions were calculated using the same methodology as NOx with the CO factors in TCEQ RG-109.

4.3.4 SO_2

An estimated sulfur specification for gas routed to the flare was converted to a per million standard cubic feet basis using projected vent gas properties and was applied to the projected flow to calculate emissions.

4.4 Engines

4.4.1 VOC

The VOC factors of 0.0013 lb/hp-hr for generators and 0.0105 lb/hp-hr for the firewater pump were used with design brake horsepower to calculate hourly emissions for each individual engine. Annual usage was used with hourly emissions to calculate annual emissions.

4.4.2 NOx

The "NOx + TOC" specification for the applicable size category is conservatively taken as the NOx factor. The required emission specification for NOx for the appropriate size category was used with design brake horsepower to calculate hourly emissions. Annual usage was used with hourly emissions to calculate annual emissions.

4.4.3 CO

The factor of 0.0068 lb/hp-hr for engines < 600 hp and 0.0058 lb/hp-hr for engines > 600 hp for CO from diesel engines was used with design brake horsepower to calculate hourly emissions. Annual usage was used with hourly emissions to calculate annual emissions.

4.4.4 SO_2

Because there are no emission specifications listed in the CFR for SO_2, the AP-42 factor of 3.075E-06 lb/hp-hr for engines < 600 hp and 1.2135E-05 lb/hp-hr for engines > 600 hp for SO_2 from engines using diesel with sulfur specifications conventional for the time of AP-42, as adjusted for ultra-low sulfur content required for existing diesel pools, was used with design brake horsepower to calculate hourly emissions. Annual usage was used with hourly emissions to calculate annual emissions.

4.4.5 PM/PM_{10}/$PM_{2.5}$

Emissions were calculated using the same methodology as NOx with the factor for Total PM. Fine particulates were set equal to Total PM. Annual usage was used with hourly emissions to calculate annual emissions.

4.5 Fugitive Components

4.5.1 VOC

Emissions were estimated by multiplying the projected number of components of each type (e.g., light liquid valve, gas/vapor valve, light liquid pumps etc.) by the Synthetic Organic Chemical Manufacturing Industry (SOCMI) emission factors in EPA 453/R-95-017 appropriate for the amount of ethylene in the stream, and applicable control efficiencies from instrument monitoring programs.

4.5.2 NH_3, H_2SO_4

Inorganic compounds were speciated from the total losses estimated from the SOCMI factors. Because the compounds are odorous, control credit for Audio-Visual-Olfactory (AVO) monitoring during shift walk-throughs was applied.

4.6 Furnaces

4.6.1 VOC

The VOC factor of 5.50 lb/MMscf in AP-42, Fifth Edition, Volume 1 Section 1.4 "Natural Gas Combustion" was used to estimate unburned VOC emissions from natural gas combustion in the furnaces. The factor was converted from a million standard cubic feet basis to a million British Thermal Units basis using typical natural gas properties. Design heat input, the emission factor, and continuous utilization was used for each of the furnaces to determine a mass emission rate. The cap was calculated as the sum of the individual furnace rates. Based on performance of similar units and that the emission factor only accounts for VOC emissions from natural gas combustion, the annual emissions were adjusted downward by the hydrogen content of the projected average fuel composition.

4.6.2 NOx

Emissions were estimated using lb/MMBtu factors, max heat input, continuous utilization and summation of units in the cap for the cap rate. The annual emission rate is based on an average performance of 0.01 lb/MMBtu for all eight furnaces, while the worst-case hourly emission rate is based on 0.012 lb/MMBtu and continuous utilization.

4.6.3 CO

Emissions were estimated using performance factors of 500 ppmv hourly average stack concentration, 50 ppmv annual average stack concentration, max heat input, continuous utilization and summation of units in the cap for the cap rate. The stack concentration was converted to a heat input basis using typical natural gas properties for hourly and natural gas adjustment for typical blend gas properties for annual continuous utilization.

4.6.4 SO_2

Emissions were calculated using the same methodology as VOC with the AP-42 factor of 0.60 lb/MMscf for SO_2.

4.6.5 $PM/PM_{10}/PM_{2.5}$

Emissions were calculated using the same methodology as VOC with the AP-42 factor of 7.60 lb/MMscf for Total PM (condensable and filterable portions). PM_{10} and $PM_{2.5}$ were set equal to Total PM.

4.6.6 NH_3

Emissions were calculated using the same methodology as CO with an SCR slip performance of 15 ppmv hourly average stack concentration and 10 ppmv annual average stack concentration for NH_3.

4.7 Glycol ByProduct

4.7.1 VOC

The majority of manufacturing losses from Glycol production will be routed to control. However, the vacuum system vent represents a limited flow from the vacuum condensate vessel which contains captured leakage from upstream vessels that are operated under vacuum such as the dehydrator, glycol bleed flasher, MEG purification column, MEG stripper and MEG recycle column. VOC emissions from a material balance for the vacuum system are accounted for in the emission calculations.

4.8 Glycol Thermal Oxidizer

4.8.1 VOC

The uncontrolled portion of emissions routed to thermal oxidizer control was estimated using projected vent gas flow and the control efficiency. The worst-case annual emissions from the Thermal Oxidizer are based on continuous operation.

4.8.2 NOx, CO, SO_2, $PM/PM_{10}/PM_{2.5}$, Inorganics

Products of combustion resulting from thermal oxidizer control were estimated using heat release of the projected vent gas flow and lb/MMBtu factors. The lb NOx/MMBtu factor and lb CO/MMBtu factor are based on the 100 lb NOx/MMscf and 84 lb CO/MMscf in AP-42 Table 1.4-1. The lb SO_2/MMBtu factor was converted from a gr/dscf factor for sulfur in natural gas used in the thermal oxidizer with 100% conversion to SO_2. The lb particulates/MMBtu factor was converted from the AP-42 factor of 7.6 lb/MMBtu for natural gas combustion and setting particulates equal to 100% fines (<PM_{10}, $PM_{2.5}$). The annual emission rates are based on continuous operation.

Process vents which are routed to the thermal oxidizer may include a nominal halide content. The halide content is assumed to convert 100% to HCl in the thermal oxidizer. This stream may also be seen at the Glycol flare.

During infrequent catalyst startups of limited duration, a nominal amount of NH_3 may be present in the vent to the thermal oxidizer. The NH_3 content of the stream is assumed to be present in the thermal oxidizer stack.

4.9 Ground Flare

The facility's vent gas system will include a multi-point ground flare. Emissions from the Ground Flare and the Shared Elevated flare are proposed to be capped annually.

4.9.1 VOC

A DRE of 99% was used for straight-chained organic compounds consisting of three carbons and less and 98% for other compounds. The component specific DRE was used in conjunction with projected vent gas component flows to determine component emissions and VOC emissions were calculated as the sum of components considered VOCs.

4.9.2 NOx

Projected vent gas component compositions and flow were used in conjunction with standard reference Lower Heating Values (LHVs) for the components to determine a heat release for the vent gas. The heat release was used in conjunction with factors in TCEQ RG-109 specific to the assist-type and low or high Btu content of the stream specific to each flare.

4.9.3 CO

Emissions were calculated using the same methodology as NOx with the CO factors in TCEQ RG-109.

4.9.4 SO_2

An estimated sulfur specification for gas routed to the flare was converted to a per million standard cubic feet basis using projected vent gas properties and applied to the projected flow to calculate emissions.

4.10 Loading and Unloading

4.10.1 VOC

Emissions were calculated using the methodology in AP-42 Section 5.2 "Transportation and Marketing of Petroleum Liquids." Worst-case material properties, applicable saturation factor and the same meteorological temperatures used in tank calculations were used to calculate a product loading loss factor, which was used with projected annual throughputs or pump rates to determine mass emission rates. The emissions calculated for EPN: U_LLOAD are the worst-case emissions from either truck or rail transfers.

Controlled loading operations include pyrolysis gasoline, slop, and heavy fuel oil via capture into the vent gas system, and sulfidic caustic via carbon canisters. Vent gas system emissions discussed elsewhere are conservative of the controlled pyrolysis gasoline loading losses. Pyrolysis gasoline and heavy fuel oil are calculated as a single volume using pyrolysis gasoline properties. Emissions of uncaptured pyrolysis gasoline loading are not expected at the rail rack as connections will be flanged and/or bolted; however, a 97.5% capture efficiency for truck loading is used based on TCEQ guidance[i] for semi-annual leak checking on atmospheric trucks. For sulfidic caustic loading, a control efficiency of 95% is based on use of carbon canisters.

In the Glycol area there is one unloading event into a drum with emissions. The moderator process vessel is a drum associated with the ethyl chloride drum, which stores ethyl chloride and provides it to the process when under pressure. The moderator is used for surge protection during loading of the ethyl chloride drum. VOC emissions are calculated using a worst-case estimation for pressure drop during loading and the dimensions of the drum.

4.10.2 NH_3

Aqueous ammonia for the facility's NOx control systems will be unloaded from delivery trucks to a storage drum. The storage drum will be routed to a water box, or ammonia sump, which will seal vapors generated from the drum when it is depressurized, and when it is filled. The amount of ammonia vapor to the sump from depressurizing was calculated assuming the differential pressure of the drum, and the amount from loading was estimated using the capacity of the transfer vehicle. The amount of ammonia vapor to the sump was used in conjunction with the fraction of ammonia in the space above the water level in the sump to calculate emissions.

4.11 Manufacturing Losses

4.11.1 VOC

Emissions were calculated as discussed elsewhere in this section for Flares, Storage Tanks, or specific Process Vents.

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[i] Air Permit Technical Guidance for chemical Sources: Loading Operations

4.12 MSS Activities

4.12.1 VOC

Emissions from some MSS activities with EPNs for routine operation like furnaces and boilers are anticipated to be less than the rates proposed for routine operation or routine operation caps and are not requested to be identified as separate limits for the activity. Other activities with air emissions are identified in this application under a MSS cap because they could occur anywhere across the facility. The cap rates were calculated as the sum of hourly and annual emission rates discussed below. Sitewide MSS activities except for tank MSS are covered under EPN: MSS CAP, and tank MSS activities are covered under EPN: MSS TANK.

Emissions from opening equipment were calculated based on the following types of process equipment which may be opened after depressuring and degassing to a control device during routine maintenance: vessels, exchangers, pumps, compressors, valves/pipe runs, instrumentation systems. For each equipment type, emissions from the following potential emissions-generating steps were calculated: opening, clingage, draining, and evaporation. The equipment listed is not an all-inclusive list of equipment that may be opened.

For opening, the ideal gas law was used with the type of equipment volume, worst-case material properties, and a release concentration in parts per million by volume which is conservative relative to actual Lower Explosive Limit (LEL) detection readings typical for this activity. Emissions of clingage from an estimated layer of non-vaporized material are included using equipment surface area and density of the material. Emissions from draining the material into an open pan prior to transferring to a closed container were calculated using the AP-42 loading loss equation and the amount drained. Emissions from evaporation of the drained material before it is transferred to a closed container were calculated using a commonly applied engineering equation[ii]. The maximum emissions-generating step estimation is taken as the hourly rate for that equipment type. To capture facility wide occurrence, conservative short-term and annual frequency multipliers were used for the equipment types. The resulting emissions by equipment type were summed to calculate the total emissions. This emission rate covers routine, or running maintenance in which the process unit is generally still operating.

Larger equipment volumes may be opened when the process unit is down during periodic turnaround activities. The same calculation steps described above were carried out for estimated volumes representing the largest section of equipment in the process unit. The contribution to the hourly MSS cap from equipment clearing was determined as the maximum of routine or turnaround maintenance. The contribution to the annual MSS cap from equipment clearing was determined as the sum of routine and turnaround activities.

Though the controlled purging of equipment is accounted for in the site's combustion device allowables, the site MSS Cap includes some emissions to account for portable

[ii] Ajay Kumar, N.S. Vatcha, and John Schmelzle, "Estimate Emissions from Atmospheric Releases of Hazardous Substances," Environmental Engineering World, November-December 1996, pages 20-23.

control devices that may be used for equipment that are not readily connected the plant's control system but for which controlled purging is required. The uncontrolled VOC portion is estimated using an ideal gas law equation and a portable control device efficiency.

Emissions from two types of vacuum truck operations were estimated. For low (<0.5 psia) vapor pressure material operations the AP-42 loading loss equation was used with worst case material properties and the capacity of one vacuum truck. For high (>0.5 psia) vapor pressure material operations an ideal gas law equation using the volume of the vacuum truck was used with a concentration equal to the break-through concentration of carbon canister control. Conservative hourly and annual frequency multipliers were applied to the emission rates for inclusion in the facility wide cap.

Emissions from temporary/frac tanks and totes were estimated using TankESP. Conservative hourly and annual frequency multipliers were applied to the emission rates for inclusion in the facility wide cap.

Tank maintenance activities are included under EPN: MSS TANK that are separate from the other facility wide MSS activity EPNs. Emissions were estimated for the following steps: standing idle, degassing, manual cleaning, re-filling. Breathing losses from the standing idle step were calculated using Equation 14 of API TR 2567. The uncontrolled portion of emissions from the degassing step were calculated using an ideal gas law equation with the volume of the vapor space under the landed roof, and a portable control device control efficiency. Emissions from the manual cleaning step were calculated using an ideal gas law equation with a volume that is based on the blower rate of an air mover used to evacuate the tank and a concentration change from 10% of material LEL to 0% of material LEL prior to entry by maintenance personnel.

Emissions from vapor displacement during the re-fill step were calculated using an ideal gas law equation with a worst-case representation of volume of the vapor space under the landed roof in conjunction with worst-case material properties. One tank landing at a time is estimated for the hourly cap. The annual cap was calculated based on a conservative frequency. The hourly and annual tank MSS caps also include maintenance activities on fixed roof tanks, which include degassing and manual cleaning.

4.12.2 NOx, CO, SO_2

Combustion emissions from controlled degassing of equipment not readily connected to the plant's control system are included in the Site MSS EPN (EPN: MSS CAP), and floating roof storage tanks are included in the tank MSS EPN (EPN: MSS TANK). The emissions were calculated using vendor factors for NOx and CO, and an estimated gr/dscf sulfur factor for natural gas used in the thermal oxidizer with 100% conversion to SO_2.

4.12.3 PM/PM_{10}/$PM_{2.5}$

Emissions were calculated from solids handling when catalysts, desiccants, or other materials loaded into process equipment, or when spent material is unloaded from process equipment. The calculation includes estimations of the amount of material loaded or unloaded, the percentage of material lost to atmosphere, and percentage of fine particulates (<PM_{10}, $PM_{2.5}$).

4.13 Polyethylene Conveying Air Vents

4.13.1 PM/PM_{10}/$PM_{2.5}$

High efficiency Filters (Bag and Sintered metal) and cyclones are used to contain and recover solid material back into the process and to minimize and prevent discharge of particulate matter (PM) to atmosphere, throughout the PE process (including catalyst, additives, granular and pellet products). The emission rate was calculated using the outlet grain loading for each particulate control device. The emissions occur at various points throughout each PE unit; however, the vent streams are similar and are proposed to be capped.

4.14 Polyethylene Product Residual VOC

4.14.1 VOC

Residual VOC from hydrocarbons that evolves from granular PE resin in the extruder feed bins and PE pellets in various pieces of equipment used for finishing, blending and storage was calculated by multiplying the production rate by projected hourly and annual estimates of lb VOC per million pounds of PE. Though the emissions occur at several points in each production line from the extruder feed bins to the railcar loadout hoppers, the rate is proposed on a cap basis for each production unit as it is based on unit production.

4.15 Regeneration Vents

4.15.1 VOC

In the olefins coproducts section, there are conversion steps which remove triple bonds and paired double bonds from the cracked gas mixture, and do not generate emissions to atmosphere except during regeneration of the reactor beds. An emission factor from similar sources was used in conjunction with estimated regeneration frequencies for hourly and annual emission estimations.

In the polyethylene raw meterials treatment section, there are purification steps which purge process materials with inerts such as nitrogen or hydrogen to the flare, but which are infrequently purged with inerts to atmosphere in the final steps. A conservative VOC concentration is used with the material flow to estimate emissions.

4.16 Shared Thermal Oxidizer

4.16.1 VOC

The Shared Thermal Oxidizer is a thermal oxidizer disposition shared by multiple process units at the facility. Oxidiztion will be provided by one of two identical devices operating under the emissions calculated for the EPN UFF01.

The uncontrolled portion of emissions routed to thermal oxidizer control was estimated using projected vent gas flow and 99.0% control efficiency. Although alternate vent gas control scenarios are considered, VOC emissions are calculated based on the annual emissions from the TO continuous operation.

4.16.2 NOx, CO, SO_2, $PM/PM_{10}/PM_{2.5}$

Products of combustion resulting from thermal oxidizer control were estimated using heat release of the projected vent gas flow and lb/MMBtu factors. A 0.06 lb NOx/MMBtu factor was used. The lb CO/MMBtu factor is based on the 84 lb CO/MMscf in AP-42 Table 1.4-1. The lb SO_2/MMBtu factor was converted from a gr/dscf factor for sulfur in natural gas and applied to the methane portion of the thermal oxidizer stream with 100% conversion to SO_2. The lb particulates/MMBtu factor was converted from the AP-42 factor of 7.6 lb/MMscf for natural gas combustion and setting particulates equal to 100% fines (<PM10, PM2.5). The annual emission rates are based on continuous operation.

4.17 Storage Tanks

4.17.1 VOC

Emissions were calculated using the methodology in AP-42 Chapter 7 Liquid Storage Tanks via Tank Emission Software Program (ESP). Tank ESP was utilized with projected annual throughputs, worst-case material properties, tank dimensions, fittings, and pump rates to calculate losses from fixed roof and floating storage tanks. Tank ESP output reports are included in Confidential Appendix A.3. One set is provided for the annual emission rates and a separate set is provided to support the short-term emission rate calculations. The short-term rates were calculated according to TCEQ guidance.

Emissions from tanks storing the same materials are proposed to be capped. The hourly cap is simply the sum of the hourly emissions of each tank in the cap. The annual emissions of each tank are based on the throughput of the cap; therefore, the annual cap is the sum of the standing losses of the tanks in the cap and the maximum working losses among the tanks in the cap.

4.18 Vehicle Refueling

4.18.1 VOC

Within the process area fenceline there will be a vehicle refueling station used to dispense gasoline and diesel into mobile sources such as trucks, cranes, carry decks, scissor lifts, welding machines, etc. Vehicle refueling emissions come from vapors displaced from the mobile vehicle by dispensed gasoline and from spillage. The quantity of displaced vapors depends on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rate. The AP-42 correlation in Chapter 5.2.2.3 is used to quantify potential emissions.

4.19 Wastewater

4.19.1 VOC

Wastewater emissions are based on ToxChem emissions modeling. ToxChem is an EPA-approved emission model based on the same principles used in the EPA program Water9 such as Henry's Law, Langmuir Sorption Isotherms, and Fick's Law of Diffusion. However, the ToxChem software also incorporates first and second order chemical kinetic rate functions and equations to account for partition changes in time. The model incorporates the site's collection and treatment system early design information.

SECTION 5
BACT ANALYSIS

In accordance with 30 TAC 116.111(a)(2)(c) and 40 CFR §52.21(j), Gulf Coast Growth Venture Project will utilize Best Available Control Technology (BACT)[iii] for new facilities. Per the project's location at a greenfield site, the sources identified in Table 1(a) of this application are new. For the purposes of this analysis the sources will be typed by emission source within process area ("source type"), for which a cross-listing of Facility Identification Numbers (FIN) and source type is provided in Table 5-1 of this section.

Table 5-1 List of BACT Source Types

Name	FIN	Source Type
Olefins Furnaces Cap	O_F_CAP	Furnaces
Multi-point Ground Flare	UFFLARE01	Manufacturing losses, Ground flare
Shared Elevated Flare	UFFLARE02	Manufacturing losses, Elevated flare
Olefins Unit Fugitives	O_FUG	Fugitive components
Olefins Regeneration Vent	O_ACV	Regeneration vents
Glycol Elevated Flare	GFFLARE03	Manufacturing losses, Elevated flare
Glycol Thermal Oxidizer	GX202	Manufacturing losses, Thermal Oxidizers
Glycol Vacuum System	GD503	Glycol Byproduct vent
Glycol Moderator	GD103	Loading and Unloading
Glycol Unit Fugitives	GFUG	Fugitive components
Utilities Cooling Tower	UCCT01	Cooling tower
Utilities Boiler Cap	USSG01CAP	Boilers
Shared Thermal Oxidizer	UFF01	Thermal oxidizers
Utilities Fugitives	U_FUG	Fugitive components
Engine Cap	ENGINECAP	Engines
Rail/Truck Liquid Loading	U_LLOAD	Loading and Unloading
Wastewater System	WWTP	Wastewater
Maintenance, Startup, and Shutdown Cap	MSS CAP	MSS activities
Tank Maintenance, Startup, and Shutdown Cap	MSS TANK	MSS activities

[iii] At 40 CFR Part §52.21(b)(12): "emissions limitation (including a visible emission standard) based on the maximum degree of reduction for each pollutant subject to regulation under 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."

Name	FIN	Source Type
PE Vents Cap	PE_VENT CAP	Manufacturing losses, Polyethylene conveying air vents
PE Unit Fugitives	PE_FUG	Fugitive components
PE Regen Vent	PE_REGEN	Regeneration vents
Pygas Day Tank 1	UTTK101T	Floating roof tank
Pygas Day Tank 2	UTTK102T	Floating roof tank
Sulfidic Caustic Day Tank 1	UTTK103T	Floating roof tank
Sulfidic Caustic Day Tank 2	UTTK104T	Floating roof tank
Light Oil Tank	UTTK107T	Fixed roof tank
Diesel Day Tank 1	UTTK100T	Fixed roof tank
E_Additive 1	EM_ETANK_1	Fixed roof tank
E_Additive 2	EM_ETANK_2	Fixed roof tank
E_Additive 3	EM_ETANK_3	Fixed roof tank
E_Additive 4	EM_ETANK_4	Fixed roof tank
C_Seal Oil 1	CPETANK_1	Fixed roof tank
C_Seal Oil 2	CPETANK_2	Fixed roof tank
C_Seal Oil 3	CPETANK_3	Fixed roof tank
C_Mineral Oil 1	CPETANK_4	Fixed roof tank
C_Mineral Oil 2	CPETANK_5	Fixed roof tank
C_Mineral Oil 3	CPETANK_6	Fixed roof tank
MEG Day Tank 1	GTK-502A	Fixed roof tank
MEG Day Tank 2	GTK-502B	Fixed roof tank
Catalyst 1	GTK-401	Fixed roof tank
Catalyst 2	GD-408	Fixed roof tank
Catalyst 3	GD-409	Fixed roof tank
Glycol Slop 1	GTK-501	Fixed roof tank
Heavy Glycol Tank 1	ZTTK06	Fixed roof tank
Heavy Glycol Tank 2	ZTTK08T	Fixed roof tank
Glycol Bleed Tank 1	ZTTK07	Fixed roof tank
Glycol Bleed Tank 2	ZTTK09T	Fixed roof tank
Glycol Bleed Cap	CAPTGB	Fixed roof tank
CPE Hexene	ZTTK03	Floating roof tank
EM Hexene	ZTTK04	Floating roof tank
MEG Rail and Truck Tank	GTK-502C	Fixed roof tank
Heavy Fuel Oil 1	ZTTK01	Floating roof tank
Heavy Fuel Oil 2	ZTTK02	Floating roof tank
Slop Oil Tank 1	ZTTK11T	Floating roof tank
Slop Oil Tank 2	ZWTK17T	Floating roof tank
Wastewater Slop Tank 1	ZWTK07	Floating roof tank
Wastewater Slop Tank 2	ZWTK06	Floating roof tank

Name	FIN	Source Type
Diesel Firepump	ZFTK02	Fixed roof tank
Diesel Infrastructure	ZMTK02	Fixed roof tank
Gasoline Infrastructure	ZMTK01	Fixed roof tank
Fire Training Gasoline	ZFTK04	Fixed roof tank
Site totes	TOTES	MSS activities
Inorganic Chemicals Storage	INORG	Fugitive components
Ammonia sump	U_NH3CAP	Loading and Unloading

Gulf Coast Growth Venture triggers PSD for and is subject to PSD BACT review for the following pollutants: NOx, CO, VOC, PM, PM_{10}, $PM_{2.5}$, and CO_2e. State BACT review applies to SO_2, H_2SO_4, and NH_3. The analysis for traditional criteria pollutants, NH_3, and H_2SO_4 is presented in this section, and the analysis for CO_2e is in Volume II.

BACT discussions in Texas generally take two forms: EPA's Top Down approach (Step 1 – Identify Control Technologies, Step 2 – Eliminate Technically Infeasible Options, Step 3 – Rank Remaining Control Technologies by Control Effectiveness, and Step 4- Evaluate Most Effective Controls, and Step 5 – Select BACT), and TCEQ's Three-Tier approach (Tier 1 – Comparison to recent NSR permit reviews for same process and/or industry, Tier 2 – Comparison to NSR permit reviews for different process and/or industry, Tier 3 – Economic and technical feasibility justification). TCEQ's Three-Tier analysis is approved by EPA as a way of evaluating BACT.[iv] Since the end result from either method should be the same, TCEQ guidance allows the permitee to choose either the BACT Top-Down method or the TCEQ BACT Three-Tier analysis.[v]

The incorporation of nationwide RACT/BACT/LAER Clearinghouse (RBLC) data into TCEQ's Three-Tier approach is considered equivalent to EPA's Top-Down BACT approach for the pollutants in this project subject to PSD review. BACT for each source type by pollutant is discussed below in Three-Tier style which incorporates query results from the RBLC. The RBLC Query results are provided in Table 5-3 at the end of this section. Though the RBLC provides an abundance of sources to which the source types in this application may be compared, the discussion includes special emphasis on projects at the following chemical complex sites:

- Dow Chemical Company Freeport, TX site (NSR Permit No. 107153/Project No. 185974 issued March 27, 2014 for olefins, and NSR Permit No. 114991/Project No. 201577 issued August 12, 2014 for polyethylene);
- Chevron Phillips Chemical Company Baytown, TX site (NSR Permit No. 1504A/Project No. 172655 issued August 6, 2013 for olefins) and Sweeny, TX site (NSR Permit No. 103832/Project No. 179322 issued August 8, 2013 for polyethylene);
- Formosa Chemical Company Point Comfort, TX site (NSR Permit No. 107518/Project No. 186768 issued August 8, 2014 for olefins, NSR Permit No. 107520/Project No. 186770

[iv] See, e.g., 75 Fed. Reg. 55978, 55982 & 55985 (Sept. 15, 2010): "Texas has a three-tiered BACT approach that has been previously approved by EPA" and "EPA has agreed that [TCEQ's Tier III] process yields results equivalent to [EPA's] top-down approach..."
[v] See APDG 6110v2 01/2011 Air Pollution Control pg. 11: "While the TCEQ has followed a different approach (Three Tier), the end result from using either method should be the same."

issued August 8, 2014 for polyethylene, NSR Permit No. 19198/Project No. 15072 issued January 28, 1993 for ethylene glycol);

- Shell Chemicals Company Monaco, PA site (NSR Permit No. 04-00740A/Project 77836 for olefins and polyethylene, issued June 18, 2015);
- Axiall Corporation-Lotte Chemical USA Corporation Lake Charles, LA site (NSR Permit No. 3136-V0/Project No. PER20150003 issued December 14, 2015 for olefins and Glycol);
- ExxonMobil Chemical Company Baytown Olefins Plant (NSR Permit No. 102982/Project No. 178224 issued February 19, 2014 for olefins) and Mont Belvieu Plastics Plant (NSR Permit No. 103048/Project No. 178209 issued October 7, 2013 for polyethylene).

Projects at these sites ("similar projects") are selected for discussion because their BACT determinations are recent (within the last four years), the projects are comparable in scale (large scale new units), and the petrochemical products produced by these projects are similar to the products in the Gulf Coast Growth Venture project.

Although this analysis encompasses nationwide RBLC data and detailed acknowledgment of other grassroots projects, the conclusions are case-specific on the basis of the Gulf Coast Growth Venture's design, operation, and location. The analysis consists of case-by-case determinations considering factors such as technical feasibility and economic reasonableness, and was developed along the guidelines of the following documents and resources:

- *NSR Workshop Manual: Prevention of Significant Deterioration and Nonattainment Area Permitting*, October 1990
- *Evaluating Best Available Control Technology in Air Permit Applications*, TCEQ RG-383, April 2001
- *Air Pollution Control: How to Conduct a Pollution Control Evaluation*, APDG 6110, January 2011
- "BACT for Chemical Sources," or Tier I BACT for Chemical Sources

http://www.tceq.state.tx.us/permitting/air/nav/air_bact_chemsource.html

In addition to the discussion in Section 7 of federal and state regulatory controls for this project's source types, some references to control thresholds in NSPS, NESHAP, MACT or TAC rules are included in the analysis as BACT may not allow controls less stringent than other applicable regulations.

The BACT analysis summarized in Table 5-2 of this section is discussed in detail below.

Table 5-2 BACT Summary

Source Type	Pollutant	BACT Summary
Boilers	VOC	Good combustion practices
	NOx	0.01 lb NOx/MMBtu 12moavg

Source Type	Pollutant	BACT Summary
	CO	50 ppm CO 12moavg
	SO_2	Low-sulfur fuel
	$PM/PM_{10}/PM_{2.5}$	Good combustion practices
	NH_3	10 ppm NH3 12moavg
Cooling tower	VOC	Non-contact design, monthly monitoring
	$PM/PM_{10}/PM_{2.5}$	0.0005% drift elimination
Elevated flares	VOC	99%DREC3-, 98%DREC4+
	NOx	Good combustion practices
	CO	Good combustion practices
	SO_2	Low-sulfur assist gas
Engines	VOC	NSPS design, low usage
	NOx	NSPS design, low usage
	CO	NSPS design, low usage
	SO_2	Ultra-low sulfur diesel
	$PM/PM_{10}/PM_{2.5}$	NSPS design, low usage
Fixed roof storage tanks	VOC	White/aluminum, submerged fill
Floating roof storage tanks	VOC	IFR, mechanical shoe primary seal
Fugitive components	VOC	28VHP+CNT
	NH_3, H_2SO_4	AVO
Furnaces	VOC	Good combustion practices
	NOx	0.01 lb NOx/MMBtu 12moavg
	CO	50 ppm CO 12moavg
	SO_2	Low-sulfur fuel
	$PM/PM_{10}/PM_{2.5}$	Good combustion practices
	NH_3	10 ppm NH_3 12moavg
Glycol Byproduct vent	VOC	Best management practices
Ground flare	VOC	99%DREC3-, 98%DREC4+
	NOx	Good combustion practices
	CO	Good combustion practices
	SO_2	Low-sulfur assist gas
Inorganic tanks	NH_3, H_2SO_4	AVO
Loading	VOC	Route to control if > 0.5 psia
Manufacturing losses	VOC	Route to control
MSS activities	VOC	Compliance with TCEQ conditions
Polyethylene conveying air vents	$PM/PM_{10}/PM_{2.5}$	≤ 0.01 gr/dscf
Polyethylene product residual VOC	VOC	64 lb/MMlb PE
Regeneration vents	VOC	Best management practices
Thermal oxidizer	VOC	99% DRE or 10 ppmv outlet VOC
	NOx	Good combustion practices

Source Type	Pollutant	BACT Summary
	CO	Good combustion practices
	SO_2	Low-sulfur fuel
Unloading	NH_3	Route to water box, AVO
	VOC	Best management practices (moderator)
Vehicle Refueling	VOC	AVO Inspection
Wastewater	VOC	On-site treatment system, closed conveyances

5.1 Boilers

5.1.1 VOC

The Boilers will emit VOC as a product of combusting natural gas and/or blend gas and vent gas. The Boilers will deliver steam while using vents from various pieces of equipment at the facility as part of their fuel gas.

The boilers will be designed for efficient use of the fuel gas, and good combustion techniques will be employed during operation. This will result in oxidation of organic inputs limiting VOC emissions to the AP-42 factor of 5.50 lb PM/MMscf. RBLC retrievals show this as BACT for VOC resulting from combustion of fuel.

Good combustion practices resulting in less than 5.50 lb/MMscf is BACT for fuels and vents routed to the boilers.

5.1.2 NOx

To reduce NOx emissions from the boilers, the burner configurations will incorporate low-NOx design. Selective Catalytic Reduction (SCR) add-on control is another available NOx control technology. A complete SCR system is complex and includes a reactor housing for the catalyst and NH_3 injection grid, storage and metering system. Also, an additional induced-draft capacity to overcome pressure drop due to the new catalyst bed and ductwork may be required. Uniform flow across the catalyst bed is critical, and Computational Fluid Dynamic (CFD) modeling may be necessary to ensure proper flow variance across the bed. An SCR system comes with challenges such as managing exhaust temperature to catalyst bed requirements and the storage and handling of aqueous ammonia.

The project will include SCR control in addition to low-NOx burners on all of the boilers. The selected control strategy is expected to achieve 0.01 lb NOx/MMBtu 12-month average for the boiler cap, which is the lowest NOx specification for similar projects and the RBLC. BACT performance will be ensured by Continuous Emissions Monitoring Systems (CEMS) and allows operations to respond to short-term fluctuations in the monitored concentration accounted for in the averaging of the cap. In consideration of the form of the specification in terms of units of heat input, comparison of the compliance concentration to BACT is proposed on a cap basis because the boilers operate together to consume heat input for steam. The use of low-NOx burners with SCR is BACT for NOx emissions from the boilers.

5.1.3 CO

Limited incomplete oxidation in the boilers will result in CO emissions. Some turbine applications include oxidation catalysts for CO removal; however, oxidation catalysts have been technically infeasible for similar projects, and are technically infeasible for this project as well.The use of clean-burning gaseous fuels and good combustion practices is proposed to limit in-stack CO concentration to 50 ppmvd on a 12- month average. This is Tier I BACT and consistent with the RBLC. Performance will be monitored through CEMS, allowing operations to respond to short-term fluctuations in the monitored concentration accounted for in the averaging of the compliance concentration for each boiler. The use of natural gas and/or blend gas and good combustion practices is BACT for CO emissions from the boilers.

5.1.4 SO_2 and H_2SO_4

Conversion of sulfur impurities in the fuel gas will result in minor SO_2 emissions and through subsequent conversions H_2SO_4 emissions as well. Coal or liquid fuel will not be burned by the boilers. SO_2 emissions will be limited by the use of pipeline quality sweet natural gas and/or blend gas which is inherently low in sulfur. This control method is consistent with the RBLC and BACT for similar projects. BACT performance is ensured from natural gas purchase records. Using low-sulfur fuel is BACT for SO_2 and H_2SO_4 emissions from the boilers.

5.1.5 PM/PM_{10}/$PM_{2.5}$

Some amount of incomplete combustion in the boilers will result in emissions of fine particulates. The use of clean-burning gaseous fuels and good combustion practices is proposed to limit emissions. Emissions on a lb/MMscf basis are expected to meet the 7.6 lb PM (considered to be 100% fines)/MMscf in AP-42. RBLC retreivals show this as BACT for PM resulting from combustion of fuel. Some combustion sources in recent projects (steam methane reformers) but not similar projects have proposed lower values and have fired with a consistent high hydrogen content fuel. For natural gas-fired sources this level of control is consistent with similar projects. Use of clean-burning fuels and good combustion practices is BACT for PM/PM_{10}/$PM_{2.5}$ emissions from the boilers.

5.1.6 NH_3

Collateral emissions of NH_3 will result from injection to the SCR module for NOx control. Best management practices including safe operation of the module will maintain low in-stack concentrations of NH_3. The proposed value of 10 ppmvd NH_3 at 3% O_2 on a 12-month average is consistent with similar sources which have employed SCR for NOx control (Dow Freeport, Chevron Phillips Baytown, Formosa Point Comfort, Shell PA).

Performance will be monitored with CEMS. Proper operation and monitoring of the SCR module is BACT for NH_3 emissions from the boilers.

5.2 Cooling Tower

5.2.1 VOC

The liquid drift from the counter flow mechanical draft water cooling tower may become a source of VOC. The cooling tower in the project will have non-contact design. VOC emissions will occur from exchangers which transfer heat from process fluids to the cooling water. The project will implement sampling and measurement using the procedures in Appendix P of the TCEQ Sampling Procedures Manual ("El Paso Method") to detect whether a leak has occurred and thus be able to take corrective action. Cooling water VOC concentrations above 0.08 ppmw will be repaired at the earliest opportunity but no later than the next scheduled shutdown of the process unit in which the leak occurs. Monthly monitoring is Tier I BACT and consistent with BACT for similar projects not located in nonattainment areas subject to Highly-Reactive VOC (HRVOC) rules (Formosa Point Comfort, Axial LA). Monthly analysis of the return water and proper Delay of Repair recordkeeping is BACT for VOC emissions from the cooling tower.

5.2.2 $PM/PM_{10}/PM_{2.5}$

Total Dissolved Solids (TDS) in the liquid drift of the cooling tower will be a source of particulates. The cooling tower will utilize drift eliminators which will minimize liquid drift and thus particulate emissions. The design will achieve 0.0005% drift which is consistent with other similar projects (Dow Freeport, Shell PA). BACT performance will be ensured by daily conductivity monitoring which will be correlated with TDS. Drift eliminators at 0.0005% meets or exceeds BACT for $PM/PM_{10}/PM_{2.5}$ emissions from the cooling tower.

5.3 Elevated Flares

5.3.1 VOC

Elevated flares will be used for disposition of manufacturing losses from certain sources in the project's process units as they enter flare headers in the facility's infrastructure. The Glycol elevated flare will be adequately sized for the proposed routine and Maintenance, Startup, and Shutdown (MSS) vent gas flows. The Shared Elevated Flare and Ground Flare are part of a staged system. The Shared Elevated Flare is designed for routine maintenance. Pilot lights at the tip will continuously burn pipeline quality sweet fuel to ensure the flare's readiness. A knockout drum will remove liquid from vent gas in the header prior to the stream entering a seal drum designed to prevent flashback. Vent gas that exceeds the pressure of the water seal will be combusted at the tip in a stable flame.

Smokeless operation will be ensured by providing supplemental momentum and ensuring proper mixing with air, while natural gas or ethane flow at the tip will be adjusted to ensure adequate heating value. Flame stability will be ensured by meeting the §60.18 minimum heating value content and the 40 CFR §60.18 maximum exit velocity limitations as determined by calorimeter and flow monitoring instrumentation installed in the header. Larger intermittent flows will be routed to the ground flare which enables the elevated flare to be designed for less flow variation. Continuous vent gas streams will not contain halogens. Based on a stable flame and smokeless operation for relatively steady vent streams, the flares will accomplish a DRE of 99% for straight-chained organic compounds consisting of three carbons and less and 98% for other compounds. This DRE is Tier I BACT and consistent with RBLC retrievals. A DRE of 99% for VOCs with three carbons and less and 98% other compounds is BACT for the elevated flares.

5.3.2 NOx

Thermal NOx formation will occur at the flare tip as a result of VOC control, and is quantified using established emission factors. Best management practices for the flare's operation including compliance with 40 CFR §60.18 will ensure that the combustion emissions profile from the flare is typical. Compliance with 40 CFR §60.18 is listed in the RBLC retrievals as BACT. Proper flare operation is BACT for NOx emissions from elevated flares.

5.3.3 CO

CO formation will occur at the flare tip as result of VOC control, and is quantified using established emission factors. Best management practices for the flare's operation including compliance with 40 CFR §60.18 will ensure that the combustion emissions profile from the flare is typical. Compliance is with 40 CFR §60.18 is listed in the RBLC retrievals as BACT. Proper flare operation is BACT for CO emissions from elevated flares.

5.3.4 SO_2

The streams controlled at the elevated flares will not have notable sulfur concentrations; however, sulfur in natural gas, ethane, ethylene, and limited process gases used at the flares will result in SO_2 emissions. The use of pipeline quality sweet natural gas for sweep and sweet fuels for supplemental heat will minimize SO_2 emissions. This is consistent with Tier I BACT of 0.1 grains H_2S per dscf fuel for combustion of fuel gas. Use of sweet gas for sweep and supplemental heat is BACT for SO_2 emissions from elevated flares.

5.4 Engines

5.4.1 VOC

Engines included in the project for emergency usage will emit VOC from uncombusted fuel. Modern engines are designed to minimize products of combustion and engine manufacturers are held to certification requirements in federal standards such as the Nonroad and Marine Engine Standards referenced in the NSPS for the diesel engines. The project will include only engines which meet applicable MACT and NSPS requirements and have low emissions per brake horsepower. The purpose of the project's engines will entail low annual usage on the order of 100 hours per year or less each. .

Low annual usage is consistent with BACT for similar projects (Chevron Phillips Baytown, Formosa Point Comfort). Low annual usage and purchase of MACT/NSPS-compliant designs is BACT for products of combustion such as VOC emissions from engines.

5.4.2 NOx

NOx is another product of combustion from the engines. Low annual usage is consistent with BACT for similar projects (Chevron Phillips Baytown, Formosa Point Comfort). Low annual usage and purchase of MACT/NSPS-compliant designs is BACT for products of combustion such as NOx emissions from engines.

5.4.3 CO

CO is another product of combustion from the engines. Low annual usage is consistent with BACT for similar projects (Chevron Phillips Baytown, Formosa Point Comfort). Low annual usage and purchase of MACT/NSPS-compliant designs is BACT for products of combustion such as CO emissions from engines.

5.4.4 SO_2

SO_2 will result from the conversion of fuel-bound sulfur in liquid fuel fired in the emergency engines. Modern refining technology is now capable of supplying Ultra-Low Sulfur Diesel with no more than 15 ppmw sulfur content. This is consistent with RBLC retrievals. Use of liquid fuel with limited sulfur content is consistent with BACT from similar projects. USLD usage is BACT for SO_2 from engines.

5.4.5 $PM/PM_{10}/PM_{2.5}$

Particulates (PM is considered 100% fines) is another product of combustion from the engines. Low annual usage is consistent with BACT for similar projects (Chevron Phillips Baytown, Formosa Point Comfort). Low annual usage and purchase of MACT/NSPS-compliant designs is BACT for products of combustion such as $PM/PM_{10}/PM_{2.5}$ emissions from engines.

5.5 Fixed Roof Storage Tanks

5.5.1 VOC

Evaporation in atmospheric (not pressure) storage tanks storing organics (< 0.5 psia of the stored material) results in VOC emissions. Tanks not routed to a control device will be controlled by design including a pipe for submerged loading and white or aluminum exterior resulting in lower working and standing losses. This is Tier I BACT for this emission source type. The use of submerged fill and reduced insolation is BACT for VOC emissions from atmospheric fixed roof storage tanks.

5.6 Floating Roof Storage Tanks

5.6.1 VOC

Evaporation of tanks storing materials > 0.5 psia ("high vapor pressure") is a source of VOC emissions. Tanks not routed to a control device storing high vapor pressure materials will be controlled by internal floating roof (IFR) design with mechanical shoe primary seal. This is Tier I BACT for this emission source type. The design for IFR tanks not routed to control will also include slightly cone-shaped bottoms considered "drain dry" to minimize emissions from tank landings.

This is consistent with other similar projects for tanks not routed to control (Dow Freeport). The use of vent controls or IFR with mechanical shoe primary seal and drain dry is BACT for storage of high vapor pressure materials in tanks that are not pressure tanks.

5.7 Fugitive Components

5.7.1 VOC

Mechanical connections in VOC service are a source of VOC. The project will install a large amount of equipment in VOC service; however, a Leak Detection and Repair (LDAR) program at TCEQ 28VHP level with quarterly connector monitoring (28CNTQ) will be instituted facility wide.

28VHP with 28CNTQ has been applied in recent projects subject to LAER and 28MID; however, RBLC retrievals for projects in attainment areas, as well as Tier I BACT, is 28VHP. LDAR of 28VHP is BACT for VOC from fugitive component leaks in the polyethylene areas and the utilities area. LDAR of 28VHP with 28CNTQ is BACT for the Olefin and Glycol areas.

5.7.2 NH_3, H_2SO_4

Mechanical connections in inorganic service are a source of NH_3 and H_2SO_4, including at and around NH_3 and H_2SO_4 storage areas. As these compounds are odorous, leaks will be detected during walkthroughs. This is equivalent to TCEQ Audio-Visual-Olfactory

(AVO) LDAR and is Tier I BACT and is BACT for NH_3 and H_2SO_4 from fugitive component leaks.

5.8 Furnaces

5.8.1 VOC

The Olefins furnaces will emit VOC as a product of combusting natural gas and/or blend gas. The amount of VOC will be minimized through good combustion practices to maximize run length and combustion efficiency and is expected to be less than the AP-42 factor of 5.50 lb/MMscf. RBLC retrievals show this as BACT for VOC resulting from combustion of fuel. This level of control will be demonstrated through initial stack sampling. The use of good combustion practices is BACT for VOC from furnaces.

5.8.2 NOx

The furnaces will be a considerable source of thermal NOx due to the large amount of heat needed to crack the project's feedstock. The burners in the furnaces will be low-NOx configuration. SCR will be included for all of the furnaces in the block. A 12-month average of 0.01 lb/MMBtu is proposed as BACT for the block as the furnaces operate in unison to form product. Application of SCR to all of the significant NOx sources (boilers and furnaces), though costly and with marked challenges to the project, has been BACT for similar sources (Chevron Phillips Baytown, ExxonMobil Baytown), and is proposed for Gulf Coast Growth Venture as well. Performance will be ensured by CEMS. The use of low-NOx burners with SCR for the block is BACT for NOx emissions from furnaces.

5.8.3 CO

Limited incomplete oxidation in the furnaces will result in CO emissions. The discussion in the Boilers section of the application of oxidation catalysts for CO in flue gas applies to the furnaces. A CO 12-month limit of 50 ppmvd at 3%O_2 in-stack concentration per furnace is proposed for this project. This is Tier I BACT and consistent with the RBLC. Performance will be monitored through CEMS, allowing operations to respond to short-term fluctuations in the monitored concentration accounted for in the averaging of the compliance concentration for each furnace. The proposed CO concentration is BACT for CO emissions from furnaces.

5.8.4 SO_2 and H_2SO_4

Conversion of sulfur impurities in natural gas and/or blend gas will result in SO_2 emissions and through subsequent conversions H_2SO_4 emissions as well. Coal or liquid fuel will not be burned by the furnaces. SO_2 emissions will be limited by the use of pipeline quality sweet natural gas and/or blend gas which is inherently low in sulfur. This control method is consistent with the RBLC and BACT for similar projects. BACT performance is ensured from natural gas purchase records. Using low-sulfur fuel is BACT for SO_2 and H_2SO_4 emissions from the furnaces.

5.8.5 PM/PM_{10}/$PM_{2.5}$

The Olefins furnaces will emit particulates (PM is considered 100% fines) as a product of combusting natural gas and/or blend gas. The amount of PM/PM_{10}/$PM_{2.5}$ will be minimized through good combustion practices to maximize run length and combustion efficiency and is expected to be less than emissions from the AP-42 factor of 7.60 lb/MMscf. RBLC retrievals show this as BACT for VOC resulting from combustion of natural gas fuel. Some combustion sources in recent projects (steam methane reformers) have proposed lower values and have fired with a consistent high hydrogen content fuel. The furnaces in this project could fire tail gas, a blend of tail gas and natural gas, or natural gas. This level of control will be demonstrated through stack sampling. The use of good combustion practices is BACT for $PM/PM_{10}/PM_{2.5}$ emissions from the furnaces.

5.8.6 NH_3

Collateral emissions of NH_3 will result from injection of NH_3 to the SCR module for NOx control. Best management practices including safe operation of the module will maintain low in-stack concentrations of NH_3. The proposed value of 10 ppmvd NH_3 at 3% O_2 on a 12-month average is consistent with similar sources which have employed SCR for NOx control.

Performance will be monitored with CEMS. Proper operation and monitoring of the SCR module is BACT for NH_3 emissions from the furnaces (Dow Freeport, Chevron Phillips Baytown, Formosa Point Comfort, Shell PA).

5.9 Glycol ByProduct Vent

5.9.1 VOC

Part of the CO_2 produced as a byproduct in the EO reactor is used in the Ethylene Glycol section as an intermediate and recycled through the Ethylene Glycol section. The purge on the recycle CO_2 stream is combined with rest of the CO_2 stream and sent to thermal oxidizer for controlling hydrocarbons in the stream. This is consistent with BACT for similar projects (Formosa Point Comfort).

VOC emissions from the vacuum system will be less than the applicable control threshold in NSPS NNN. Utilization of best management practices is BACT for VOC from this source.

5.10 Ground Flare

5.10.1 VOC

Certain limited scenarios at the facility's process units may generate large vent gas flows. Ground flare control technology utilizes the pressure of the vent flows to create a stable flame at each burner head activated in a system of staged risers in the refractory enclosure of the ground flare. Ground flares have additional industrial hygiene benefits such as reduced acoustics and radiant footprint. It has been shown through testing in support of BACT for similar projects (Dow Freeport [PDH]) that the pressure-assist burners destructing similar short-chained olefin molecules can obtain a minimum of 99% DRE at heating values greater than the §60.18 minimum and exit velocities above the §60.18 maximum. Ground flares have been selected as BACT for intermittent flows at similar projects (Dow Freeport) and issued Alternative Means of Emission Limitation (AMELs) and Alternative Method of Control (AMOCs). Consistent with the AMEL/AMOCs, the ground flare will have instrumentation to show a heating value monitoring system and consistent with the facility's ground flare authorizations once they are issued.

DRE of 99% for straight-chain organic compounds of three carbons or less and 98% for other compounds is Tier I BACT and is BACT for intermittent flows controlled by ground flare.

5.10.2 NOx

Thermal NOx is formed at the burner tip and is estimated using established emissions factors. Vent flows will be staged through the risers using the system's manifold, and the flare will be operated to prevent visible emissions and maintain a typical combustion emissions profile. Proper flare operation is BACT for NOx emissions from the ground flare.

5.10.3 CO

CO formation will occur at the tips and is estimated using established emissions factors. Vent flows will be staged through the risers using the system's manifold, and the flare will be operated to prevent visible emissions and maintain a typical combustion emissions profile. Proper flare operation is BACT for CO emissions from the ground flare.

5.10.4 SO_2

Natural gas, ethane, ethylene, and limited process gases used at the flares will result in SO_2 emissions. The use of pipeline quality sweet natural gas and /or ethane for sweep and supplemental heat will minimize SO_2 emissions. This is consistent with Tier I BACT of 0.1 grains H_2S per dscf fuel for combustion of fuel gas. Use of sweet gas for sweep and supplemental heat is BACT for SO_2 emissions from the ground flare.

5.11 Loading and Unloading Losses

5.11.1 VOC

Some vapor displacement in rail cars and truck cargo tanks will occur during the loading of facility materials at the truck/rail transfer racks within the inner fenceline. Liquid loading operations of a cargo vessel is a coordinated effort between the operations at the facility and the representative of the transfer vessel. Numerous pre-transfer steps are carried out to ensure that the cargo is transferred to the vessel according to all requirements. The loading operation is continuously monitored by personnel. Low vapor pressure (< 0.5 psia) compounds can be loaded by submerged fill or bottom loading without vapor collection; however, loading of high vapor pressure (> 0.5 psia) compounds such as pyrolysis gasoline will be connected to a vent gas system. Submerged fill/bottom loading for low vapor pressure compounds and routing to control for high vapor pressure compounds is Tier I BACT and is BACT for transfers at racks within the inner fenceline.

The unloading activity to fill the Glycol Moderator drum will be conducted according to standard procedures, resulting in < 0.10 tpy VOC. Best management practices including following standard operating procedure is BACT for this source.

5.11.2 NH_3

Emissions from unloading aqueous ammonia for the facility's NOx control systems from delivery trucks to the storage drum are controlled by sparging the drum vapor outage to a water sump sized for > 99% absorption of ammonia. This method of control for the unloading operation is recognized by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRE) as documented through their standard 15-2010 and the California Mechanical Code section 1120.0. Audio, olefactory, and visual checks for leaks following the 28AVO fugitive program will be made while the sump is in use. This level of control is consistent with similar projects (ExxonMobil Baytown[vi]).

Routing the drum to a water sump and 28AVO are BACT for NH_3 from unloading activities.

5.12 Manufacturing Losses

5.12.1 VOC

The vent gas system will collect various vent gases produced at the facility for disposition as discussed in Section 3.4. The vent gas system includes boilers, thermal oxidizers, elevated flares, and a ground flare. The selection of the appropriate control devices provides flexibility for the facility to ensure efficient vent gas control and maintain fuel gas containment during planned operating scenarios. Similar equipment has been permitted at various projects. This section discusses the disposition of vent gas streams for VOC in relation to recently permitted similar projects. The control technology review for the boilers, flares, and thermal oxidizersis discussed in Sections 5.1, 5.3, 5.10, and 5.17 of this analysis.

VOC manufacturing losses will result from vents such as regenerations, seal leakage, pressure relief leakage, surges, and drains. During high pressure flow scenarios, such as some planned startups or shutdowns, process equipment will relieve to the flare system which is consistent with similar projects. Formosa Point Comfort, Dow Freeport, and Shell Pennsylvania have routed olefins manufacturing losses to a flare system. The Chevron Phillips Cedar Bayou project routed the low pressure vents to a boiler or a thermal oxidizer that backs up the boiler.

VOC manufacturing losses will result from Glycol process equipment mechanisms such as from stripper vents, reactor vents, and vapor purges. Vapor purges tie into the Glycol thermal oxidizer as the primary disposition. Flows from startup, shutdown, or alternate dispositions will be routed to an elevated flare. The Axiall-Lotte Lake Charles project routed Glycol manufacturing losses to a combination of thermal oxidizer and flare.

VOC manufacturing losses from polyethylene which occur upstream of the purger such as vent recovery system lean gas, cycle gas, purification bed regenerations and compressor seals will have tie-ins to the vent gas system. High pressure flows such as during planned startups, shutdowns and product grade transitions will relieve to the

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[vi] TCEQ Project No. 245967

elevated flare, ground flare, or the thermal oxidizer. The other similar projects (Chevron Phillips Sweeny, Shell Pennsylvania, and Dow Freeport) routed polyethylene manufacturing losses upstream of the purger to flare.

5.13 MSS Activities

5.13.1 VOC

Various MSS activities necessary to maintain the integrity and working order of equipment will result in VOC emissions. Some activities have negligible PTE ("Inherently Low Emitting") and were estimated by type and frequency in this application. Depressuring and degassing equipment to the vent gas system prior to opening for inspection or maintenance will result in emissions at the control devices, and opening the equipment may release VOC at levels verified to be within safety limits.

The vent gas system MSS emissions are the result of carefully coordinated actions between Maintenance and Operations personnel which serve to prepare equipment for maintenance where there is a ready connection to a vent gas system, and the amount of material to be combusted is more than 50 lb of air contaminant. This involves blocking in the equipment, opening valves to the vent gas system, and applying inert gas to purge the equipment. Process unit startup and shutdown operations will result in intermittent flows which could be of high volume and pressure which the ground flare is designed to control. Flare and thermal oxidizer technology for the project is described elsewhere in this section and will achieve the same DRE for MSS flows as for routine.

The opening of equipment to atmosphere occurs only after coordination and planning within the facility's Process Safety Management practices. VOC content of the vapor space in process vessels that have been prepared for maintenance will be verified per standard procedures used to ensure that equipment is de-energized. Process vessels are generally only opened during unit-wide turnaround events, while smaller pieces of equipment (exchangers, compressors, pumps, sampling and instrumentation systems, pipe runs, etc) may be opened during routine maintenance triggered by work orders at any time of the year.

Floating roof tanks will be de-inventoried and maintained according to their API inspection schedules. The emptying, degassing, cleaning, opening, and refilling of these tanks will occur in an efficient sequence that will minimize VOC emissions. The degassing step will be a controlled operation utilizing a portable control device such as an engine or T.O. The design of the tanks will incorporate sloped bottoms which will minimize vaporization from liquid heel.

Vacuum trucks will be used in various maintenance operations to transport slops or wastewater from tanks and sumps. Vacuum truck operations for high vapor pressure materials will be controlled.

Portable ("frac") tanks will be used at the facility for temporary storage of materials during some maintenance activities. Frac tanks will have fixed roof tank-type control with exteriors which minimize solar insolation and will be submerged loaded. This requirement will not apply to tanks/vessels that only vent to atmosphere when being filled, sampled, gauged, or when removing material.

The sitewide MSS permit limit caps encompass equipment opening, tank maintenance, vacuum trucks and frac tanks. The stack related limits for the boilers and furnaces will encompass their combustion related MSS emissions. The typically higher short-term emissions from startup, shutdown, hot standby and SCR warm-up operations of the boilers and furnaces will be accounted for in the pollutant averaging of their respective BACT limitations, but will generally be limited by the duration of the activities.

As TCEQ is a leader in requiring MSS BACT, RBLC data does not offer much for comparison relative to similar projects in Texas. The MSS activities represented in this application will be conducted in accordance with common TCEQ permit language which is nearly identical for similar projects in Texas.

Controlling equipment purge volumes down to below the lower of either 10,000 ppmv or 10% of the Lower Explosive Limit (LEL), controlled degassing of tanks, drain-dry floating roof tank design, controlled vacuum trucks for high vapor pressure materials, frac tanks with fixed roof tank-type control, and operation of boilers and furnaces within their averaged BACT values is BACT for the project's MSS.

5.14 Polyethylene Conveying Air Vents

5.14.1 $PM/PM_{10}/PM_{2.5}$

Blowers used to provide motive force for additives, granules, and pellets in the Polyethylene units will have air streams with entrained particulates. Particulate control devices such as cyclones and filters will be used to recover product and also minimize particulate emissions to the atmosphere. All environmental dust control devices in the application will be designed to meet an outlet grain loading of < 0.01 gr/dscf which is more stringent than some similar sources (Dow Freeport, Chevron Phillips Sweeny, Formosa Point Comfort) as well as Tier I BACT (0.01 gr/dscf) but equal to other similar sources (Shell PA). This level of control is provided by design. The proposed outlet grain loading is BACT for $PM/PM_{10}/PM_{2.5}$ emissions from conveying air vents.

5.15 Polyethylene Product Residual VOC

5.15.1 VOC

In polyethylene production downstream of the purger, conveying air (which has generally been controlled for particulates) may carry hydrocarbon that was not captured in the recovery section of the process and has evolved out of the molecular chains of the product during residence time in storage and handling vessels. The conveying air vents are either below the Calculated Threshold Exemption or individual exemption concentrations in NSPS DDD.

The recovery section will include properly sized purge vessels and compressors for recycle gases from the resin that flows to the purge vessels back into the reactors. The performance of the system is indicated by the sampled VOC concentration and plastics production in terms of lb VOC/MMlb PE. This application proposes an annually averaged 64 lb VOC/MMlb PE which meets or exceeds TCEQ's Tier 1 BACT of 80 lb VOC/MMlb PE[vii]. The product will be sampled and tested monthly for residual VOC to show compliance with BACT requirements. The amount of VOC that remains bound and dissolved in the polyethylene product structure varies with different grades; the estimated lb VOC/MMlb PE factor is a calculation variable used to cover the range of expected product grades.

Recently permitted polyethylene processes have proposed a range of residual VOC factors for the establishment of allowable limits based on case-by-case design considerations. Despite process design differences, the proposed value is between the low end and high end of the scale of similar projects (from 50 lb VOC/MMlb PE for Shell Pennsylvania to 73 lb VOC/MMlb PE for Dow Freeport to 155 lb VOC/MMlb PE for Formosa Point Comfort).

Proper design of the recovery and purging section of the process and 64 lb VOC/MMlb PE is BACT for residual VOC in PE.

5.16 Regeneration Vent

5.16.1 VOC

The process will periodically regenerate equipment used to minimize triple bonds and paired double bonds in Olefins and treat process materials in Polyethylene. The emissions to atmosphere at safe height and location are not continuous but are the result of operations necessary to maintain control of the process. Best management practices will be utilized during regeneration which will restrict emissions to the proposed rates. The magnitude of proposed emissions is comparable to rates permitted in other recently permitted Olefins unit operations (Formosa Point Comfort), and is less than the applicable control threshold in NSPS NNN (TRE > 8.0) or NSPS DDD. Utilization of Best management practices is BACT for VOC emissions from this source.

5.17 Thermal Oxidizers

5.17.1 VOC

For control of vent gas streams from various units in this project, thermal oxidizers are selected as vent gas disposition based on heating value, flow characteristics and other design considerations. A regenerative thermal oxidizer uses ceramic beds to retain heat from previous vent gas to use for incoming vent gas, reducing fuel consumption in the warm-up burner. The T.O. will be appropriately sized and configured to obtain a high DRE; however, the regenerative T.O. technology generally has a lower DRE than direct-

[vii] "Uncontrolled VOC < 80 lb/MMlb for low pressure HDPE and case-by-case for high pressure LDPE" according to "BACT for Chemical Sources,"

fired due to minimal entrainment of vent gas during ceramic bed cycles. A direct fired thermal oxidizer combusts vent gas directly in the combustion chamber. The selection of thermal oxidizer type considers the characteristics of the streams being routed to the thermal oxidizer.

MACT requirements for vent gas disposition under HON and MON include destruction of HAPs to a minimum of 98%. A direct fired thermal oxidizer is selected as the disposition for vents from the facililty, and Glycol process vents. The selected thermal oxidizer technology will achieve either a DRE of at least 99%, or an outlet VOC concentration of 10 ppmv which is consistent with Tier I BACT and similar projects (Axial-Lotte, Formosa Point Comfort, Dow Freeport). The proposed DREs/outlet VOC concentration is BACT for VOC from the TOs.

5.17.2 NOx

Thermal NOx formation will occur in the combustion chamber.

The Shared T.O. will achieve 0.06 lb/MMBtu NOx 12-month average, which is as low as the lowest that has been issued as BACT among similar projects (Dow Freeport). The emissions will be limited using good combustion techniques. This is BACT for the Shared T.O.

The Glycol T.O. is a smaller unit controlling streams resulting in appreciably less heat release than the Shared T.O. Good combustion practices will be used to limit emissions to be equivalent to the AP-42 factor of 100 lb NOx/MMscf. Use of good combustion practices is BACT for the Glycol T.O.

5.17.3 CO

Thermal CO formation will occur in the combustion chamber. Good combustion practices will be used to limit emissions to be equivalent to the AP-42 factor of 84 lb CO/MMscf. Proper T.O. operation is BACT for CO from the T.O.

5.17.4 SO_2

Natural gas and limited process gas used at the T.O. will result in SO_2 emissions. The use of pipeline quality sweet natural gas for sweep and sweet fuels for supplemental heat will minimize SO_2 emissions. This is consistent with Tier I BACT of 0.1 grains H_2S per dscf fuel for combustion of fuel gas. Use of natural gas for vent gas enrichment is BACT for SO_2 from thermal oxidizers.

5.18 Vehicle Refueling

5.18.1 VOC

Vehicle refueling emissions come from vapors displaced from the mobile vehicle by dispensed gasoline and from spillage. The quantity of displaced vapors depends on gasoline temperature, auto tank temperature, gasoline RVP, and dispensing rate. The AP-42 correlation in Chapter 5.2.2.3 is used to quantify potential emissions; however, emissions from spillage will be minimized through best management practices which include avoiding leaks and performing inspections for liquid leaks, visible vapors, or significant odors resulting from fuel transfers. Transfers will be discontinued immediately if liquid leaks, visible vapors or significant odors are observed and will not resume until the observed issue is repaired. Best management practices including AVO inspection is BACT for this source.

5.19 Wastewater

5.19.1 VOC

Wastewater generated in processes will contain VOC. The facility's infrastructure will include drainage, closed piping and hydraulics to transport wastewater to an on-site wastewater treatment plant. The treatment plant will be designed according to good engineering principles and concepts, including oil removal, followed by a secondary activated sludge bioreactor (including clarifiers) to treat the wastewater streams from process units and potentially contaminated storm water runoff from process paved areas. The recovered oil storage and flow equalization tanks will meet BACT requirements for storage tanks and also the requirements of NSPS Kb.

The treatment plant will treat water to the requirements established through National Pollutant Discharge Elimination System (NPDES) permitting prior to entering natural watersheds. The treatment system will include a Benzene Waste Operations NESHAP (BWON) control device to remove benzene. Equipment subject to BWON will be designed according to BWON standards.

In terms of BACT for similar projects, these controls are similar to another project which included in its scope a new wastewater treatment plant (Shell PA). Closed vent piping, waste management units incorporating BWON design, and a wastewater treatment plant with primary and secondary levels is BACT for VOC from wastewater.

Table 5-3 RBLC Query Results

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Firing of pipeline quality natural gas and high-hydrogen process gas. : 26.27 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Carbon Monoxide	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Good combustion practices and firing of high hydrogen process gas : 50 PPMVD @ 3% O2
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Nitrogen Oxides (NOx)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Good combustion practices, firing of high hydrogen process gas and selective catalytic reduction. : 0.01 LB/MMBTU 12-MO AVERAGE
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Particulate matter, total < 10 µ (TPM10)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Firing of pipeline quality natural gas and high hydrogen process gas. : 5.74 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Particulate matter, total < 2.5 µ (TPM2.5)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Firing of pipeline quality natural gas and high hydrogen process gas. : 5.74 TPY

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Fugitives	28VHP fugitive monitoring program : 4.61 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Carbon Monoxide	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Fugitives	28VHP fugitive monitoring program : 7.7 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer Start up and Shutdown	flare:99% DRE for VOC molecules with three compounds or less, including methanol and CO (high hydrogen). 98% DRE for all other compounds. Flare shall meet 40 CFR §60.18 minimum Btu and maximum tip velocity requirements. : 0
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Carbon Monoxide	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer Start up and Shutdown	Flare: The flare will combust excess syngas which contains high concentrations of hydrogen and CO. 99% DRE for CO.: 353.9 TPY

Table 5-3 RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	analyzer vent	: 0.89 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Carbon Monoxide	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	analyzer vent	: 6.5 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Cooling Tower	Minimize VOC leaks into cooling water : 3.65 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Particulate matter, total < 10 µ (TPM10)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Cooling Tower	Drift eliminators meeting 0.001% drift : 3.07 TPY
TICONA POLYMERS , INC.	BISHOP FACILITY	TX	Particulate matter, total < 2.5 µ (TPM2.5)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Cooling Tower	Drift eliminators meeting 0.001% drift : 0.01 TPY

Table 5-3 RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
TICONA POLYMERS, INC.	BISHOP FACILITY	TX	Volatile Organic Compounds (VOC)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Storage Tanks	Submerged fill, white tanks with internal floating roofs. : 6.86 TPY
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Nitrogen Oxides (NOx)	12/1/2014	108446/PSD TX1352	Heat Transfer Fluid (HTF) Heaters	NOx emissions from the HTF heaters will be reduced using selective catalytic reduction (SCR) technology involving injection of aqueous ammonia: 0.02 LB/MMBTU BOTH HOURLY&ANNUAL AVG. FOR NORMAL OPS.
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Carbon Monoxide	12/1/2014	108446/PSD TX1352	Heat Transfer Fluid (HTF) Heaters	good combustion : 0.0365 LB/MMBTU BOTH HOURLY&ANNUAL AVG. FOR NORMAL OPS.
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Volatile Organic Compounds (VOC)	12/1/2014	108446/PSD TX1352	Heat Transfer Fluid (HTF) Heaters	Fuel gas firing : 0.0054 LB/MMBTU HRLY AND ANNUAL,FOR FUEL GAS FIRING
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Ammonia (NH3)	12/1/2014	108446/PSD TX1352	Heat Transfer Fluid (HTF) Heaters	Heaters have low NOx burners with Selective Catalytic Reduction (SCR). Ammonia slip is 10 ppmvd in the slip stream from SCR: 10 PPMVD HRLY & ANNUALIN THE SLIP STREAM FROM SCR

Table 5-3 RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Volatile Organic Compounds (VOC)	12/1/2014	108446/PSD TX1352	Regenerative Thermal Oxidizer	Thermal destruction with 99% DRE for VOC or 10 ppmv outlet concentration at 3% oxygen in exhaust : 10 PPMV HRLY AND ANNUAL, AT 3% OXYGEN IN EXHAUST
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Volatile Organic Compounds (VOC)	12/1/2014	108446/PSD TX1352	Flare	Meet 40CFR60.18 for steam assisted flare : 99 PERCENT DRE AT ALL TIMES
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Ammonia (NH3)	12/1/2014	108446/PSD TX1352	Storage Tanks	Scrubber with 85% removal efficiency is used to control ammonia from the storage tank vents : 0.02 HOURLY
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Volatile Organic Compounds (VOC)	12/1/2014	108446/PSD TX1352	Storage Tanks	Emissions from all tank farm tanks will be routed to a caustic scrubber. Scrubber will achieve 95% reduction for acetic acid and ethylene glycol : 0.68 LB/H HOURLY
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Nitrogen Oxides (NOx)	12/1/2014	108446/PSD TX1352	Engines	Each emergency generator's emission factor is based on EPA's Tier 2 standards at 40CFR89.112 for NOx : 5.43 G/KW-H

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
M&G RESINS USA, LLC	PROJECT JUMBO	TX	Sulfur Dioxide (SO2)	12/1/2014	108446/PSD TX1352	Engines	Ultra low sulfur fuel engines burn will meet the sulfur requirement of 15 ppm in 40CFR80.510(b) : 0.0649 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Reformer Furnace	Low-NOx burners, SCR : 0.0109 LB/MMBTU 30-DAY AVERAGE ROLLED DAILY
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Reformer Furnace	good combustion practices : 0.02 LB/MMBTU 30-DAY AVERAGE ROLLED DAILY
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Reformer Furnace	good combustion practices : 0.0019 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total < 10 µ (TPM10)	9/5/2014	13060007	Reformer Furnace	good combustion practices : 0.0024 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total <2.5 µ (TPM2.5)	9/5/2014	13060007	Reformer Furnace	good combustion practices : 0.0024 LB/MMBTU 3-HOUR AVERAGE

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Reformer Furnace	good combustion practices : 0.0054 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Boiler	low-NOx burners, scr (or equivalent) : 0.012 LB/MMBTU 30-DAY AVERAGE ROLLED DAILY
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Boiler	good combustion practices : 0.02 LB/MMBTU 30-DAY AVERAGE ROLLED DAILY
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Boiler	good combustion practices : 0.0019 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 10 µ (TPM10)	9/5/2014	13060007	Boiler	good combustion practices : 0.0024 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 2.5 µ (TPM2.5)	9/5/2014	13060007	Boiler	good combustion practices: 0.001 LB/MMBTU 3-HOUR AVERAGE
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Boiler	good combustion practices : 0.0054 LB/MMBTU 3-HOUR AVERAGE

Table 5-3 RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Startup Heater	low-nox burners : 0.08 LB/MMBTU
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Startup Heater	good combustion practices: 0.037 LB/MMBTU
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Startup Heater	good combustion practices : 0.0019 LB/MMBTU
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 10 µ (TPM10)	9/5/2014	13060007	Startup Heater	good combustion practices : 0.0075 LB/MMBTU
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 2.5 µ (TPM2.5)	9/5/2014	13060007	Startup Heater	good combustion practices : 0.0075 LB/MMBTU
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Startup Heater	good combustion practices : 0.0054 LB/MMBTU

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization; nitrogen as purge gas : 0.07 LB/MMBTU
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 0.37 LB/MMBTU
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 0.1 TPY
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total $< 10\ \mu$ (TPM10)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 0.25 TPY
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total $<2.5\ \mu$ (TPM2.5)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 0.25 TPY
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 0.21 TPY

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.67 G/KW-H
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 3.5 G/KW-H
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 10 µ (TPM10)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Particulate matter, total < 2.5 µ (TPM2.5)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.4 G/KW-H

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Nitrogen Oxides (NOx)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 3.5 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Carbon Monoxide	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 3.5 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, filterable (FPM)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total < 10 µ (TPM10)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Particulate matter, total < 2.5 µ (TPM2.5)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.1 G/KW-H
CRONUS CHEMICAL S, LLC	CRONUS CHEMICAL S, LLC	IL	Volatile Organic Compounds (VOC)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 0.4 G/KW-H

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
ROHM AND HAAS TEXAS INCORPORATED	CHEMICAL MANUFACTURING FACILITY	TX	Nitrogen Oxides (NOx)	12/20/2013	2165 PSDTX1320	(2) boilers	Selective Catalytic Reduction: 0.01 LB/MMBTU 1 HOUR
ROHM AND HAAS TEXAS INCORPORATED	CHEMICAL MANUFACTURING FACILITY	TX	Carbon Monoxide	12/20/2013	2165 PSDTX1320	(2) boilers	good combustion practices : 50 PPMVD @3% O2, ONE HOUR AVERAGE
ROHM AND HAAS TEXAS INCORPORATED	CHEMICAL MANUFACTURING FACILITY	TX	Particulate matter, total < 2.5 µ (TPM2.5)	12/20/2013	2165 PSDTX1320	(2) boilers	good combustion practices, use of gaseous fuels : 0
SOLVAY CHEMICALS	GREEN RIVER SODA ASH PLANT	WY	Nitrogen Oxides (NOx)	11/18/2013	MD-13083	Natural Gas Package Boiler	low NOx burners and flue gas recirculation : 0.011 LB/MMBTU 30-DAY ROLLING
SOLVAY CHEMICALS	GREEN RIVER SODA ASH PLANT	WY	Carbon Monoxide	11/18/2013	MD-13083	Natural Gas Package Boiler	good combustion practices: 0.037 LB/MMBTU 30-DAY ROLLING
SOLVAY CHEMICALS	GREEN RIVER SODA ASH PLANT	WY	Volatile Organic Compounds (VOC)	11/18/2013	MD-13083	Natural Gas Package Boiler	good combustion practices: 0.0054 LB/MMBTU 3-HR AVERAGE

Table 5-3 RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
SOLVAY CHEMICALS	GREEN RIVER SODA ASH PLANT	WY	Particulate matter, total (TPM)	11/18/2013	MD-13083	Natural Gas Package Boiler	good combustion practices: 0.007 LB/MMBTU 3-HR AVERAGE
AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	BAYPORT COMPLEX	TX	Carbon Monoxide	9/5/2013	9346 PSDTX612 M2	(3) gas-fired boilers	good combustion practices : 50 PPMVD @3% O2, 3-HR ROLLING AVERAGE
AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	BAYPORT COMPLEX	TX	Particulate matter, total < 2.5 µ (TPM2.5)	9/5/2013	9346 PSDTX612 M2	(3) gas-fired boilers	good combustion practices : 0
AIR LIQUIDE LARGE INDUSTRIES U.S., L.P.	BAYPORT COMPLEX	TX	Nitrogen Oxides (NOx)	9/5/2013	9346 PSDTX612 M2	(3) gas-fired boilers	Selective Catalytic Reduction (SCR) : 0.01 LB/MMBTU 3 HOUR ROLLING AVERAGE
ENTERPRISE PRODUCTS OPERATING LLC	ENTERPRISE MONT BELVIEU COMPLEX	TX	Volatile Organic Compounds (VOC)	11/14/2012	100091,PSD TX1286 AND N154	Heaters	Proper design and operation of the heaters : 0.68 LB/H

Table 5-3 RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
ENTERPRISE PRODUCTS OPERATING LLC	ENTERPRISE MONT BELVIEU COMPLEX	TX	Volatile Organic Compounds (VOC)	11/14/2012	100091,PSD TX1286 AND N154	Flare	proper flare design and operation in accordance with NSPS 60.18. 99.5% DRE for VOC. : 4.75 TPY
ENTERPRISE PRODUCTS OPERATING LLC	ENTERPRISE MONT BELVIEU COMPLEX	TX	Carbon Monoxide	11/14/2012	100091,PSD TX1286 AND N154	Flare	proper flare design and operation in accordance with NSPS 60.18: 41.21 LB/H
ENTERPRISE PRODUCTS OPERATING LLC	ENTERPRISE MONT BELVIEU COMPLEX	TX	Volatile Organic Compounds (VOC)	11/14/2012	100091,PSD TX1286 AND N154	Tanks	Proper design and operation of tanks : 0.76 LB/H
ENTERPRISE PRODUCTS OPERATING LLC	ENTERPRISE MONT BELVIEU COMPLEX	TX	Volatile Organic Compounds (VOC)	11/14/2012	100091,PSD TX1286 AND N154	Fugitive Components	28LAER leak detection and repair program : 1.29 LB/H

SECTION 6
GHG BEST AVAILABLE CONTROL TECHNOLOGY

See Volume II for an analysis of GHG Best Available Control Technology.

SECTION 7
REGULATORY APPLICABILITY

GCGV will comply with State Air Regulations in Title 30 of the TAC (30 TAC) and Federal Air Regulations in Title 40 of the CFR (40 CFR). A high-level discussion of potentially applicable regulations is provided in this section. Applications for Title V permits will be submitted at a later date with all required regulatory applicability information.

7.1 State Air Regulations

7.1.1 30 TAC Chapter 101 – General Rules

The facility will be operated in accordance with the General Rules relating to circumvention, nuisance, traffic hazard, notification requirements for major upset, notification requirements for maintenance, sampling, sampling ports, emission inventory requirements, sampling procedures and terminology, compliance with Environmental Protection Agency Standards, emissions fees, and all other applicable General Rules.

7.1.2 30 TAC Chapter 111 – Control of Air Pollution from Visible Emissions and Particulate Matter

The operation of this facility may result in occasional visible emissions but not in excess of the opacity limits specified in Chapter 111, §111.111. Engines, furnaces and boilers, and flares in the facility will comply with the visible emissions requirement and recordkeeping requirements specified in §111.111(a)(1)(B), §111.111(a)(1)(C), and §111.111(a)(4)(A), respectively. The facility will comply with the allowable particulate matter (PM) emission rate specified in §111.151.

7.1.3 30 TAC Chapter 112 – Control of Air Pollution from Sulfur Compounds

The highest sulfur-containing fuel to be burned on a routine basis will be pipeline-quality, sweet natural gas. Sulfur content in the natural gas is expected to be less than 5 grains per 100 dscf; therefore, sulfur compound emissions will be low (as shown in the emission calculations). Upon request of the Executive Director, atmospheric dispersion modeling results will be submitted, verifying that the 30-minute property line standards specified in §112.3 for sulfur dioxide emissions will not be exceeded.

7.1.4 30 TAC Chapter 113 – Standards of Performance for Hazardous Air Pollutants and for Designated Facilities and Pollutants

TCEQ has incorporated MACT standards (40 CFR Part 63) into Chapter 113 by reference. Portions of this regulation dealing with the MACT standards, as discussed under "Federal Air Regulations" apply to the project. The facility will comply with all applicable provisions of §113.100 (Subpart A), §113.110 (Subpart F), §113.120 (Subpart G), §113.130 (Subpart H), §113.130 (Subpart Y), §113.560 (Subpart YY), §113.880

(Subpart EEEE), §113.890 (Subpart FFFF), and §113.1090 (Subpart ZZZZ) concerning control, recordkeeping, reporting and monitoring requirements.

7.1.5 30 TAC Chapter 114 – Control of Air Pollution from Motor Vehicles

Motor vehicles are not required to be included in PSD permitting. This rule does not apply to the facility.

7.1.6 30 TAC Chapter 115 – Control of Air Pollution from Volatile Organic Compounds

The proposed facility is located in San Patricio County, which is a covered attainment county. The provisions under this regulation are applicable to emission sources in this permit application.

Storage of Volatile Organic Compounds, §115.112 - §115.119

Storage tanks in the project will be subject to the regulatory requirements specified under Chapter 115. The facility will comply with the applicable control, recordkeeping, reporting, and monitoring requirements.

Vent Gas Control, §115.120 - §115.129

Process vents from facilities will be subject to the regulatory requirements specified under Chapter 115. VOC vent gas streams which are not exempt from control will comply with the required emission specifications and control requirements specified in §115.121 and §115.122, and all other applicable recordkeeping and reporting requirements.

Loading and Unloading of Volatile Organic Compounds, §115.211 - §115.219

Loading and unloading operations of VOCs with a true vapor pressure of 0.5 psia or greater will be controlled in accordance with §115.212. Loading and unloading activities will comply with the applicable control, recordkeeping, and monitoring requirements.

Fugitive Emission Controls §115.352 - §115.359

Fugitive components at the facility will be subject to Chapter 115 for Fugitive Components in VOC service. The facility will meet all applicable control, recordkeeping, reporting, monitoring, and testing requirements.

7.1.7 30 TAC Chapter 116 – Control of Air Pollution by Permits for New Construction or Modification

Pursuant to 30 TAC §116.111, the facility will meet all rules and regulations of the TCEQ and the intent of the Texas Clean Air Act (TCAA) for the emission sources and activities addressed in this permit application, as follows:

Rule 116.111(a)(2)(A), Protection of Public Health and Welfare

As outlined below, the emissions from the facility will comply with all air quality rules and regulations and with the intent of the TCAA, including protection of the health and physical property of the people. In addition, there are no schools located within 3,000 feet of the facility as demonstrated in Figure 2-1.

Rule 116.111(a)(2)(B), Measurement of Emissions

Emissions from facilities specified in this application will be tested upon request by the Executive Director of the TCEQ.

Rule 116.111(a)(2)(C), Best Available Control Technology (BACT)

Best Available Control Technology (BACT) is described in Section 5 and Section 6 of this application.

Rule 116.111(a)(2)(D), Federal New Source Performance Standards (NSPS)

Some emission sources at the facility will be subject to NSPS such as boilers, tanks, polyethylene vents, distillation towers, reactors, and engines as discussed in "Federal Air Regulations." The facility will comply with all applicable control, recordkeeping, reporting, and monitoring requirements.

Rule 116.111(a)(2)(E), National Emission Standards for Hazardous Air Pollutants (NESHAP)

Equipment components in benzene service will be subject to 40 CFR Part 61 Subpart J and benzene waste control at the facility will be subject to the requirements in 40 CFR Part 61 Subpart FF. The facility will comply with all applicable control, recordkeeping, reporting, and monitoring requirements associated with these NESHAPs.

Rule 116.111(a)(2)(F), National Emission Standards for Hazardous Air Pollutants (MACT)

Process units at the facility will either be considered Synthetic Organic Chemical Manufacturing Industry (SOCMI) Chemical Manufacturing Process Units (CMPUs) subject to the standards in 40 CFR Part 63, Subparts F, G, and H, affected facilities under 40 CFR Part 63, Subpart YY, or may be Miscellaneous Chemical Process Units (MCPUs) subject to 40 CFR Part 63, Subpart FFFF. Loading at the facility will be potentially subject to 40 CFR Part 63, Subparts Y and EEEE. Engines at the facility will be subject 40 CFR Part 63, Subpart ZZZZ. The facility will comply with all applicable control, recordkeeping, reporting, and monitoring requirements associated with these MACT standards.

Rule 116.111(a)(2)(G), Performance Demonstration

The facility will perform as represented in the permit application. The facility will provide additional data as requested to demonstrate that the proposed facility will achieve the performance specified in the permit application.

Rule 116.111(a)(2)(H), Nonattainment Review

The facility is located at an area classified as attainment for all pollutants including the 8-

hr ozone standard. As such, Nonattainment Review does not apply.

Rule 116.111(a)(2)(I), Prevention of Significant Deterioration (PSD) Review

PSD Review will be required as stated in Section 2 of this application.

Rule 116.111 (a)(2)(J), Air Dispersion Modeling

GCGV will provide dispersion modeling results upon the request of the TCEQ. The appropriate modeling protocols will be submitted before providing any modeling results to the TCEQ.

Rule 116.111 (a)(2)(K), Hazardous Air Pollutant

The facility will be a source of 25 tpy or more of any combination of HAPs and as such is expected to be a new major source of HAPs as defined in the Federal Clean Air Act (FCAA) §112(b).

However, these sources will be subject to established MACT standards; therefore, are not subject to FCAA, §112(g).

Rule 116.111 (a)(2)(L), Mass Cap and Trade

The Cap and Trade program does not apply to the area in which the facility will be located.

Rule 116.150 New Major Source or Major Modification in Ozone Nonattainment Areas

The facility is located in an area classified as attainment for all pollutants including the 8-hr ozone standard. As such, Nonattainment Review does not apply.

7.1.8 30 TAC Chapter 117 – Control of Air Pollution from Nitrogen Compounds

Industrial, Commercial, and Institutional Combustion Sources in Ozone Nonattainment Areas, §117.301 - §117.356

The facility will not be located in an area subject to Chapter 117 control.

7.1.9 30 TAC Chapter 118 – Control of Air Pollution Episodes

The facility will be operated in compliance with the rules relating to generalized and localized air pollution episodes.

7.1.10 30 TAC Chapter 122 – Federal Operating Permits

The source will be subject to the Title V permitting requirements of Chapter 122. A Title V application will be submitted to the TCEQ under a separate cover.

7.2 Federal Air Regulations

7.2.1 40 CFR Part 60, Subpart A – General Provisions

General monitoring, recordkeeping and reporting requirements under this subpart will apply for NSPS affected sources in the project as specified in the applicable NSPS standard. The facility will comply with these provisions as well as flare operating requirements applicable through referencing subparts.

7.2.2 40 CFR Part 60, Subpart Db – Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

The project's boilers will be new steam generating units with design capacity above the applicability thresholds in the rule. GCGV will comply with the provisions of this rule, including NOx CEMS monitoring.

7.2.3 40 CFR Part 60, Subpart Kb – Standards of Performance for Volatile Organic Liquid Storage Vessels (Including Petroleum Liquid Storage Vessels) for which Construction, Reconstruction, or Modification Commenced after July 23, 1984

The project will include storage tanks above the size and vapor pressure applicability thresholds of the rule. Tanks subject to the rule will be designed in accordance with the rule, including floating roof design or closed vent capture system. The facility will comply the inspection and notification requirements of the rule.

7.2.4 40 CFR Part 60, Subpart VV – Standards of Performance for Equipment Leaks of VOC in the Synthetic Organic Chemicals Manufacturing Industry for which Construction, Reconstruction, or Modification Commenced After January 5, 1981, and on or Before November 7, 2006

This rule includes equipment leak monitoring and repair provisions for equipment installed prior to the construction date of the project; however, it will apply to polyethylene production equipment in the project through the referencing Subpart DDD. The facility will comply with these provisions for the polyethylene units.

7.2.5 40 CFR Part 60, Subpart VVa – Standards of Performance for Equipment Leaks for VOC in the Synthetic Organic Chemicals Manufacturing Industry (SOCMI) for which Construction, Reconstruction, or Modification Commenced after November 7, 2006

This rule includes equipment leak monitoring and repair provisions for equipment installed after the construction date of the rule. As the project includes new SOCMI facilities, the facility will comply with the provisions of this rule. The rule will not apply in addition to Subpart VV to the polyethylene units because they do not produce Subpart VVa (or Subpart VV) listed chemicals.

7.2.6 40 CFR Part 60, Subpart DDD – Standards of Performance for VOC Emissions from the Polymer Manufacturing Industry

This rule includes provisions for affected facilities within a process. The polyethylene units will comply with the requirements of this subpart, including control design for applicable vents and the fugitive leak monitoring referenced in Subpart VV.

7.2.7 40 CFR Part 60, Subpart NNN – Standards of Performance for VOC Emissions from SOCMI Industry Distillation Operations

Disposition of vents associated with distillation operations is regulated under this rule. As the project includes new SOCMI facilities, GCGV will comply with the provisions of this rule or overlap provisions in applicable MACT standards.

7.2.8 40 CFR Part 60, Subpart RRR – Standards of Performance for VOC Emissions from SOCMI Reactor Processes

Disposition of vents associated with reactor vessels is regulated under this rule. As the project includes new SOCMI facilities, the facility will comply with the provisions of this rule or overlap provisions in applicable MACT standards.

7.2.9 40 CFR Part 60, Subpart IIII – Standards of Performance for Stationary Compression Ignition Internal Combustion Engines

This provision includes design requirements for engine manufacturers and operation and maintenance requirements for owner/operators. Although the engines included in the project are considered to be for emergency use only, the project will purchase engines certified to meet or exceed the applicable emission limitations.

7.2.10 40 CFR Part 61, Subpart A – General Provisions

General monitoring, recordkeeping and reporting requirements under this subpart will apply to the project as the facility will be a major source of HAPs with applicability to one or more Part 61 NESHAPs. The facility will comply with these provisions.

7.2.11 40 CFR Part 61, Subpart J – Equipment Leaks (Fugitive Emission Sources) of Benzene

Though benzene-containing wastes will be treated on-site and thus not be stored and transferred in grades that trigger applicability to Subparts Y and BB, there may some components in benzene service subject to Subpart J. The facility will comply with any applicable requirements in this subpart.

7.2.12 40 CFR Part 61, Subpart FF – National Emissions Standard for Benzene Waste Operations

The project will include processes that generate benzene waste that trigger Benzene Waste Operations NESHAP (BWON) applicability. GCGV will manage facility benzene wastes according to a compliance strategy in the rule, including on-site treatment (e.g., steam stripping).

7.2.13 40 CFR Part 63, Subpart A – General Provisions

General monitoring, recordkeeping and reporting requirements under this subpart will apply for project sources subject to MACT standards as specified in the applicable MACT standard. The facility will comply with these provisions as well as flare operating requirements applicable through referencing subparts.

7.2.14 40 CFR Part 63, Subpart F – National Emission Standards for Organic Hazardous Air Pollutants from the SOCMI Industry

The Glycol unit will be considered a Chemical Manufacturing Process Unit (CMPUs) subject to emission standards, control device performance and continuous monitoring applicable through the Hazardous Waste Organic NESHAP ("the HON") in Subparts F, G, and H. Subpart F contains requirements for heat exchange systems and maintenance wastewater, as well as the definitions, details and clarifications for HON strategy. General monitoring, recordkeeping and reporting requirements under this subpart will apply for NSPS affected sources in the project. The facility will comply with the applicable requirements in this subpart.

7.2.15 40 CFR Part 63, Subpart G – National Emission Standards for Organic Hazardous Air Pollutants from the SOCMI Industry for Process Vents, Storage Vessels, Transfer Operations, and Wastewater

This subpart contains requirements for various HON emission sources. The facility will comply with the applicable requirements in this subpart.

7.2.16 40 CFR Part 63, Subpart H – National Emission Standards for Organic Hazardous Air Pollutants from the SOCMI Industry for Equipment Leaks

This subpart contains HON fugitive equipment leak monitoring and repair requirements, including quarterly connector monitoring. The facility will comply with the applicable requirements in this subpart.

7.2.17 40 CFR Part 63, Subpart YY – National Emission Standards for Hazardous Air Pollutants for Source Categories: Generic Maximum Achievable Control Technology Standards

The Olefins unit will be applicable to Subpart YY ("the Generic MACT"), which has emission standards, recordkeeping and notification requirements. GCGV will comply with these requirements as well as applicable requirements in subparts referenced by the Generic MACT, including 40 CFR Part 63, Subpart XX – National Emissions Standards for Ethylene Manufacturing Process Units: Heat Exchange Systems and Waste Operations.

7.2.18 40 CFR Part 63, Subpart EEEE – National Emission Standards for Hazardous Air Pollutants for Source Categories: Organic Liquids Distribution (Non-Gasoline)

Products from the Olefins and Glycol units that will be loaded across truck and rail points will potentially be subject to this subpart ("the OLD MACT"). The facility will comply with applicable control device and notification requirements referenced therein.

7.2.19 40 CFR Part 63, Subpart FFFF – National Emission Standard for Hazardous Air Pollutants: Miscellaneous Organic Chemical Manufacturing

This subpart contains requirements for process vents, storage tanks, transfer racks, heat exchange systems and wastewater sources at Miscellaneous Chemical Process Units (MCPUs). This rule could potentially apply to polyethylene units at the facility based on catalyst usage. The facility will comply with applicable MON standards.

7.2.20 40 CFR Part 63, Subpart ZZZZ – National Emission Standard for Hazardous Air Pollutants for Stationary Reciprocating Internal Combustion Engines

This subpart contains operation and maintenance requirements for engine owner/operators at major and area HAP sources. The facility will comply with the requirements of this subpart for the emergency engines.

7.2.21 40 CFR Part 63, Subpart DDDDD – National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters

This subpart contains emission standards for units firing fuel types such as coal or oil, and work practice requirements for units firing fuel types such as natural gas or fuel gas. The Olefins furnaces are not subject to this subpart as process heaters at ethylene units are specifically exempt. The Utilities boilers burn natural gas or fuel gas and are subject to periodic tune-up requirements. The facility will comply with the applicable requirements in this subpart.

APPENDIX A

Any request for portions of this application that are marked as confidential must be submitted in writing, pursuant to the Public Information Act, to the TCEQ Public Information Coordinator, MC 197, P.O. Box 13087, Austin, Texas 78711-3087.

SAGE ATC
ENVIRONMENTAL CONSULTING

GULF COAST
GROWTH VENTURES

Prevention of Significant Deterioration Permit Application for Gulf Coast Growth Venture Project (GCGV)

Volume II: GHG PSD Application

GCGV Asset Holding LLC

Gregory, Texas

April 2017

AIR PERMITS DIVISION

APR 19 2017

HAND-DELIVERED

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LIST OF APPENDICES

SECTION 1
TCEQ ADMINISTRATIVE FORMS

1.1 Administrative Forms

The following forms and tables are included in this section in the following order, in support of this application:

- Table 1(a) – Emission Point Summary.

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume II*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
O_FAF01	O_FAF01	Furnace A	(1)	--	(1)
O_FBF01	O_FBF01	Furnace B	(1)	--	(1)
O_FCF01	O_FCF01	Furnace C	(1)	--	(1)
O_FDF01	O_FDF01	Furnace D	(1)	--	(1)
O_FEF01	O_FEF01	Furnace E	(1)	--	(1)
O_FFF01	O_FFF01	Furnace F	(1)	--	(1)
O_FGF01	O_FGF01	Furnace G	(1)	--	(1)
O_FHF01	O_FHF01	Furnace H	(1)	--	(1)
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	CO_2	--	1,555,774.36
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	CH_4	--	129.80
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	N_2O	--	25.96
O_F_CAP	O_F_CAP	Olefins Furnaces Cap	CO_2e	--	1,566,755.63

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
UFFLARE01	UFFLARE01	Multi-point Ground Flare	(2)	--	(2)
UFFLARE02	UFFLARE02	Shared Elevated Flare	(2)	--	(2)
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	CO_2	--	137,887.71
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	CH_4	--	86.31
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	N_2O	--	1.38
CAPUFFLR	CAPUFFLR	Shared Elevated and Ground Flare Cap	CO_2e	--	140,456.36
O_ACV	O_ACV	Olefins Regeneration Vent	CO_2	--	11.98
O_ACV	O_ACV	Olefins Regeneration Vent	CO_2e	--	11.98
GFFLARE03	GFFLARE03	Glycol Elevated Flare	(4)	--	(4)
GX202V	GX202V	Gylcol Vent	(4)	--	(4)
GX202	GX202	Glycol Thermal Oxidizer	(4)	--	(4)
GLYCAP	GLYCAP	Glycols Cap	CO_2	--	425,835.32
GLYCAP	GLYCAP	Glycols Cap	CH_4	--	193.24
GLYCAP	GLYCAP	Glycols Cap	N_2O	--	0.91
GLYCAP	GLYCAP	Glycols Cap	CO_2e	--	430,938.10
USSG01A	USSG01A	Utilities Boiler A	(5)	--	(5)

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AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
USSG01B	USSG01B	Utilities Boiler B	(5)	--	(5)
USSG01C	USSG01C	Utilities Boiler C	(5)	--	(5)
USSG01CAP	USSG01CAP	Utilities Boiler Cap	CO_2	--	676,557.06
USSG01CAP	USSG01CAP	Utilities Boiler Cap	CH_4	--	45.63
USSG01CAP	USSG01CAP	Utilities Boiler Cap	N_2O	--	9.13
USSG01CAP	USSG01CAP	Utilities Boiler Cap	CO_2e	--	680,417.66
UFF01_A	UFF01_A	Shared Thermal Oxidizer A	(6)	--	(6)
UFF01_B	UFF01_B	Shared Thermal Oxidizer B	(6)	--	(6)
UFF01	UFF01	Shared Thermal Oxidizer Cap	CO_2	--	63,536.78
UFF01	UFF01	Shared Thermal Oxidizer Cap	CH_4	--	191.84
UFF01	UFF01	Shared Thermal Oxidizer Cap	N_2O	--	0.64
UFF01	UFF01	Shared Thermal Oxidizer Cap	CO_2e	--	68,522.08
U_GEN1	U_GEN1	Emergency Generator No. 1	(7)	--	(7)
U_GEN2	U_GEN2	Emergency Generator No. 2	(7)	--	(7)
U_GEN3	U_GEN3	Emergency Generator No. 3	(7)	--	(7)
U_GEN4	U_GEN4	Emergency Generator No. 4	(7)	--	(7)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume II*

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Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR
U_GEN5	U_GEN5	Emergency Generator No. 5	(7)	--	(7)
U_FWP	U_FWP	Firewater Pump No. 1	(7)	--	(7)
G_GEN6	G_GEN6	Glycol Generator No. 1	(7)	--	(7)
ENGINECAP	ENGINECAP	Engine Cap	CO_2	--	71.80
ENGINECAP	ENGINECAP	Engine Cap	CH_4	--	<0.01
ENGINECAP	ENGINECAP	Engine Cap	N_2O	--	<0.01
ENGINECAP	ENGINECAP	Engine Cap	CO_2e	--	72.05
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	CO_2	--	117.88
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	CH_4	--	0.36
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	N_2O	--	<0.01
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	CO_2e	--	127.13
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	CO_2	--	314.34
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	CH_4	--	0.95
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	N_2O	--	<0.01
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	CO_2e	--	339.01
O_FUG	O_FUG	Olefins Unit Fugitives	CH_4	--	3.84

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TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume II*

Date:	**Apr 2017**	**Permit No.:**	**TBD**	**Regulated Entity No.:**	**TBD**
Area Name:	**Gulf Coast Growth Ventures (GCGV)**			**Customer Reference No.:**	**TBD**

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

AIR CONTAMINANT DATA					
1. Emission Point			**2. Component or Air Contaminant Name**	**3. Air Contaminant Emission Rate**	
(A) EPN	**(B) FIN**	**(C) NAME**		**(A) POUND PER HOUR**	**(B) TONS PER YEAR**
O_FUG	O_FUG	Olefins Unit Fugitives	CO_2e	--	96.03
E_FUG	E_FUG	EM PE Unit Fugitives	CH_4	--	(8)
E_FUG	E_FUG	EM PE Unit Fugitives	CO_2e	--	(8)
C_FUG	C_FUG	CPE Unit Fugitives	CH_4	--	(8)
C_FUG	C_FUG	CPE Unit Fugitives	CO_2e	--	(8)
PE_FUG	PE_FUG	PE Unit Fugitives	CH_4	--	0.09
PE_FUG	PE_FUG	PE Unit Fugitives	CO_2e	--	2.23
GFUG	GFUG	Glycol Unit Fugitives	CO_2	--	0.95
GFUG	GFUG	Glycol Unit Fugitives	CH_4	--	1.00
GFUG	GFUG	Glycol Unit Fugitives	CO_2e	--	25.84
U_FUG	U_FUG	Utilities Fugitives	CH_4	--	2.94
U_FUG	U_FUG	Utilities Fugitives	CO_2e	--	73.48
PE_REGEN	PE_REGEN	PE Treater Regeneration	CO_2	--	38.40
PE_REGEN	PE_REGEN	PE Treater Regeneration	CO_2e	--	38.40

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary - *Volume II*

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA					
1. Emission Point			2. Component or Air Contaminant Name	3. Air Contaminant Emission Rate	
(A) EPN	(B) FIN	(C) NAME		(A) POUND PER HOUR	(B) TONS PER YEAR

Notes:

(1) Emissions from Furnaces A - H are listed in Ethylene Furnaces Cap.

(2) Elevated and Ground Flare Cap is the sum of annual emissions from Elevated Flare and Ground Flare during all modes of operation. This cap does not include the Glycols Elevated Flare.

(3) Emissions from Glycols Elevated Flare Intermittent and Continuous modes of operation are capped.

(4) Glycols Cap includes Flare, Glycols Vent, and Thermal Oxidizer GHG.

(5) Emissions from Boilers A, B, and C are listed in Utilities Boilers Cap.

(6) Two Thermal Oxidizers. Maximum annual rate accounts for both.

(7) Emissions from Emergency Generator Engine Nos. 1 through 5, Firewater Pump Engine, and Glycol Generator Engine are listed in Engine Cap.

(8) Fugitive emissions from both EPE and CPE Polyethylene Units are combined in PE Fugitives.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

TCEQ

Table 1(a) Emission Point Summary - Volume II

Date:	Apr 2017	Permit No.:	TBD	Regulated Entity No.:	TBD
Area Name:	Gulf Coast Growth Ventures (GCGV)			Customer Reference No.:	TBD

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

AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS										
1. Emission Point			4. UTM Coordinates of Emission Point			Source							
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
O_FAF01	O_FAF01	Furnace A	15	665046	3090578	10	190	8	50	282			
O_FBF01	O_FBF01	Furnace B	15	665054	3090392	10	190	8	50	282			
O_FCF01	O_FCF01	Furnace C	15	665063	3090407	10	190	8	50	282			
O_FDF01	O_FDF01	Furnace D	15	665072	3090422	10	190	8	50	282			
O_FEF01	O_FEF01	Furnace E	15	665082	3090441	10	190	8	50	282			
O_FFF01	O_FFF01	Furnace F	15	665091	3090457	10	190	8	50	282			
O_FGF01	O_FGF01	Furnace G	15	665099	3090471	10	190	8	50	282			
O_FHF01	O_FHF01	Furnace H	15	665108	3090486	10	190	8	50	282			
UFFLARE01	UFFLARE01	Multi-point Ground Flare	15	665369	3090502	10	TBD	TBD	TBD	TBD			
UFFLARE02	UFFLARE02	Shared Elevated Flare	15	665311	3090595	10	TBD	TBD	TBD	TBD			
O_ACV	O_ACV	Olefins Regeneration Vent	15	664859	3090542	10	75	1	0.10	215			
GFFLARE03	GFFLARE03	Glycol Elevated Flare	15	664275	3090867	10	TBD	TBD	TBD	TBD			
GX202	GX202	Glycol Thermal Oxidizer	15	664350	3090800	10	TBD	TBD	TBD	TBD			
USSG01A	USSG01A	Utilities Boiler A	15	665195	3090600	10	150	10	54	350			
USSG01B	USSG01B	Utilities Boiler B	15	665185	3090584	10	150	10	54	350			
USSG01C	USSG01C	Utilities Boiler C	15	665175	3090565	10	150	10	54	350			
UFF01_A	UFF01_A	Shared Thermal Oxidizer A	15	665251	3090633	10	TBD	TBD	TBD	TBD			
UFF01_B	UFF01_B	Shared Thermal Oxidizer B	16	665220	3090651	10	TBD	TBD	TBD	TBD			
U_GEN1	U_GEN1	Emergency Generator No. 1	15	664700	3090737	10	10	0.70	225	400			
U_GEN2	U_GEN2	Emergency Generator No. 2	15	664933	3090686	10	10	0.70	225	400			
U_GEN3	U_GEN3	Emergency Generator No. 3	15	664700	3090737	10	10	0.70	225	400			
U_GEN4	U_GEN4	Emergency Generator No. 4	15	665078	3090608	10	10	0.70	225	400			
U_GEN5	U_GEN5	Emergency Generator No. 5	15	665592	3090096	10	10	0.70	225	400			
U_FWP	U_FWP	Firewater Pump No. 1	15	664713	3090364	10	10	0.70	225	400			

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

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AIR CONTAMINANT DATA			EMISSION POINT DISCHARGE PARAMETERS											
1. Emission Point			4. UTM Coordinates of Emission Point			Source								
						5. Building	6. Height Above	7. Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	Name (C)	Zone	East (Meters)	North (Meters)	Height (Ft.)	Ground (Ft.)	Diameter (Ft.) (A)	Velocity (FPS) (B)	Temperature (°F) (C)	Length (Ft.) (A)	Width (Ft.) (B)	Axis Degrees (C)
G_GEN6	G_GEN6	Glycol Generator No. 1	15	664700	3090737	10	10	0.70	225	400			
MSS CAP	MSS CAP	Maintenance, Startup, and Shutdown Cap	15	664540	3090726	10	12	3	63	1400			
MSS TANK	MSS TANK	Tank Maintenance, Startup, and Shutdown Cap	15	664618	3090352	10	12	3.34	63	1400			
O_FUG	O_FUG	Olefins Unit Fugitives	15	664859	3090542	10	20	0.003	0.003	ambient			
E_FUG	E_FUG	EM PE Unit Fugitives	15	665042	3091001	10	20	0.003	0.003	ambient			
C_FUG	S_FUG	Conventional PE Unit Fugitives	15	665208	3090906	10	20	0.003	0.003	ambient			
GFUG	GFUG	Glycols Unit Fugitives	15	664540	3090726	10	20	0.003	0.003	ambient			
U_FUG	U_FUG	Utilities Fugitives	15	665028	3090718	10	10	0.003	0.003	ambient			
PE_REGEN	PE_REGEN	PE Treater Regeneration	15	665208	3090906	10	108	2.000	88.000	158			

EPN = Emission Point Number
FIN = Facility Identification Number

SECTION 2
INTRODUCTION

Please see Volume I for the Introduction.

SECTION 3
PROCESS DESCRIPTION

Please see Volume I for Process Description.

SECTION 4
CALCULATION METHODOLOGY DISCUSSION

The project will result in emissions of the following pollutants: CO_2e. The potential-to-emit (PTE) of each of these pollutants for the sources covered in this application was estimated using commonly accepted engineering principles and established emission factors. Provided below is a general description of each emission calculation. Detailed calculations are documented in the tables in Confidential Appendix B.1.

4.1 Boilers

Boilers for VOC, NOx, CO, SO_2, $PM/PM_{10}/PM_{2.5}$, NH_3 are all included in **Volume I.**

4.1.1 VOC – Volume I

4.1.2 NOx – Volume I

4.1.3 CO – Volume I

4.1.4 SO_2 – Volume I

4.1.5 $PM/PM_{10}/PM_{2.5}$ – Volume I

4.1.6 NH_3 – Volume I

4.1.7 CO_{2e}

Emissions were calculated consistent with GHG Mandatory Reporting Rule (MRR) Tier 3 calculation methodology in 40 CFR § 98.33 (Subpart C). The design fuel flow for each boiler was used in conjunction with representative carbon content and molecular weight fuel gas properties to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart C. The respective Global Warming Potentials (GWPs) of 25 for CH_4 and 298 for N_2O from 40 CFR Part 98 (Table A-1, updated December 11, 2014) were used to convert them to CO_2e emissions, and total GHG emissions are given as the sum of all CO_2e emissions.

4.2 Cooling Tower – Volume I

4.3 Elevated Flares

4.3.1 VOC – Volume I

4.3.2 NOx - Volume I

4.3.3 CO - Volume I

4.3.4 SO_2 - Volume I

4.3.5 CO_2e

Emissions from flares were estimated consistent with GHG MRR calculation methodology in 40 CFR § 98.253 (Subpart Y). The gas flow to the tip was used in conjunction with the default CO_2 emission factor of 60 kilograms CO_2/MMBtu in § 98.253 to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart Y. The respective GWPs were used to convert them to CO_2e emissions, and total GHG emissions are given as the sum of all CO_2e emissions.

4.4 Engines

4.4.1 VOC – Volume I

4.4.2 NOx - Volume I

4.4.3 CO - Volume I

4.4.4 SO_2 - Volume I

4.4.5 PM/PM_{10}/ $PM_{2.5}$ - Volume I

4.4.6 CO_2e

Emissions were estimated consistent with the GHG MRR methodology in 40 CFR Part 98, Subpart C. Estimated fuel usage was used with the fuel-specific factor in Tables C-1 and C-2 of Subpart C for each pollutant. The respective GWPs for CH_4 and N_2O were used to convert the emissions to CO_2e emissions, and total GHG emissions are given as the sum of all CO_2e emissions.

4.5 Fugitive Components

4.5.1 VOC – Volume I

4.5.2 NH_3, H_2SO_4 – Volume I

4.5.3 CO_2e

Emissions were calculated using a conservative assumption of the maximum weight percent of CH_4 in the process fluids and emissions from gas/vapor and light liquid service components added for the fugitive areas. CH_4's GWP was used to convert the emissions to an annual CO_2e emission rate.

4.6 Furnaces

4.6.1 VOC – Volume I

4.6.2 NOx – Volume I

4.6.3 CO – Volume I

4.6.4 SO_2 – Volume I

4.6.5 PM/PM_{10}/ $PM_{2.5}$ - Volume I

4.6.6 NH_3 – Volume I

4.6.7 CO_2e

Emissions were calculated consistent with GHG Mandatory Reporting Rule (MRR) Tier 3 calculation methodology in 40 CFR § 98.33 (Subpart C). The design fuel flow for each furnace was used in conjunction with representative carbon content and molecular weight fuel gas properties to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart C. The respective Global Warming Potentials (GWPs) for CH_4 and N_2O from 40 CFR Part 98 (Table A-1, updated December 11, 2014) are used to convert them to CO_2e emissions, and total GHG emissions are given as the sum of all CO_2e emissions.

4.7 Glycol Byproduct Vent

4.7.1 VOC – Volume I

4.7.2 CO_2e

CO_2 is the dominant component of the vent flow from Glycol production whether it occurs at the Thermal Oxidizer during normal operation (EPN: GX202), or at the Glycol Elevated Flare (EPN: GFFLARE03). The projected flow and CO_2 concentration were used to estimate CO_2e emissions. Emissions of CO_2, CH_4, and N_2O from oxidation of organic components are calculated for the Thermal Oxidizer and Flare as discussed elsewhere in this section.

Emissions from the Glycol T.O., Flare, and Byproduct vent are proposed to be capped in one set of annual limits.

4.8 Glycol Thermal Oxidizer

4.8.1 VOC - Volume I

4.8.2 NOx, CO, SO_2, PM/PM_{10}/$PM_{2.5}$, Inorganics – Volume I

4.8.3 $CO_{2}e$

Emissions were calculated consistent with GHG MRR calculation methodology in 40 CFR Part 98, Subpart Y (similar to flares). The gas flow to the T.O. was used in conjunction with the default CO_2 emission factor of 60 kilograms CO_2/MMBtu in § 98.253 to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart Y. The respective GWPs were used to convert them to $CO_{2}e$ emissions, and total GHG emissions are given as the sum of all $CO_{2}e$ emissions. The $CO_{2}e$ Glycol T.O. and the Glycol Byproduct vent are capped.

4.9 Ground Flare

4.9.1 VOC – Volume I

4.9.2 NOx – Volume I

4.9.3 CO – Volume I

4.9.4 SO_2 – Volume I

4.9.5 $CO_{2}e$

Emissions from the flare were estimated consistent with GHG MRR calculation methodology in 40 CFR § 98.253 (Subpart Y). The gas flow to the tip was used in conjunction with the default CO_2 emission factor of 60 kilograms CO_2/MMBtu in 40 CFR § 98.253 to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart Y. The respective GWPs were used to convert them to $CO_{2}e$ emissions, and total GHG emissions are given as the sum of all $CO_{2}e$ emissions.

4.10 Loading and Unloading – Volume I

4.11 Manufacturing Losses – Volume I

4.12 MSS Activities

4.12.1 VOC– Volume I

4.12.2 NOx, CO, SO_2– Volume I

4.12.3 PM/PM_{10}/$PM_{2.5}$– Volume I

4.12.4 CO_2e

Emissions were calculated consistent with GHG MRR calculation methodology in 40 CFR Part 98, Subpart Y (similar to flares). The gas flow to the portable T.O. during degassing activities was used in conjunction with representative carbon content and molecular weight gas properties to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart Y. The respective GWPs were used to convert them to CO_2e emissions, and total GHG emissions are given as the sum of all CO_2e emissions.

4.13 Polyethylene Conveying Air Vents – Volume I

4.14 Polyethylene Product Residual VOC– Volume I

4.15 Regeneration Vents

4.15.1 VOC, CO – Volume I

4.15.2 CO2e

The conversion steps in the Olefins coproducts section remove triple bonds and paired double bonds from the cracked gas mixture, and do not generate emissions to atmosphere except during regeneration of the reactor beds. Emission factors from similar sources and process knowledge were used in conjunction with estimated regeneration frequencies for hourly and annual emission estimations.

In the polyethylene raw materials treatment section, there are purification steps which purge process materials with inerts such as nitrogen or hydrogen to the flare, but which are infrequently purged with inerts to atmosphere in the final steps. A conservative CO_2 concentration was used with the material flow to estimate emissions.

4.16 Shared Thermal Oxidizer

4.16.1 VOC - Volume I

4.16.2 NOx, CO, SO2, PM/PM10/PM2.5 – Volume I

4.16.3 $CO_{2}e$

Emissions were calculated consistent with GHG MRR calculation methodology in 40 CFR Part 98, Subpart Y (similar to flares). The gas flow to the T.O. was used in conjunction with the default CO_2 emission factor of 60 kilograms CO_2/MMBtu in 40 CFR § 98.253 to calculate annual emissions of CO_2. Emissions of CH_4 and N_2O were calculated using fuel flow and the factors in Part 98, Subpart Y. The respective GWPs were used to convert them to $CO_{2}e$ emissions, and total GHG emissions are given as the sum of all $CO_{2}e$ emissions.

4.17 Storage Tanks – Volume I

4.18 Vehicle Refueling – Volume I

4.19 Wastewater – Volume I

SECTION 5
BACT ANALYSIS

Please see Volume I for BACT Analysis.

SECTION 6
GHG BEST AVAILABLE CONTROL TECHNOLOGY

The Gulf Coast Growth Venture Project is expected to exceed the PSD thresholds for a number of criteria pollutants and the PSD GHG emissions threshold of 75,000 tpy CO_2e.

Therefore, the sources that will emit GHG and are subject to GHG PSD BACT review are:

- Boilers;
- Engines;
- Flares;
- Fugitive components;
- Furnaces;
- Glycol Byproduct vent;
- Glycol Thermal Oxidizer;
- Regeneration Vents; and
- Shared Thermal Oxidizer.

Process heaters and boilers are discussed in different subsections; however, elements of the boilers analysis which are identical to elements of the process heaters analysis will refer to the boilers analysis. All flares whether they are elevated or ground-level are under the same subsection. There is no existing equipment included in the project.

6.1 BACT Analysis Methodology

BACT is defined in 40 CFR Part §52.21(b)(12) as "...an emission limitation based on the maximum degree of reduction for each pollutant subject to regulation under the Act which would be emitted from a source which on a case-by-case basis is determined to be achievable taking into account energy, environmental and economic impacts and other costs."

BACT is also defined in 30 TAC §116.10(1) as: "An air pollution control method for a new or modified facility that through experience and research, has proven to be operational, obtainable, and capable of reducing or eliminating emissions from the facility, and is considered technically practical and economically reasonable for the facility. The emissions reduction can be achieved through technology such as the use of add-on control equipment or by enforceable changes in production processes, systems, methods, or work practice."

In the USEPA guidance documents titled the *1990 Draft New Source Review Workshop Manual*, USEPA recommends the use of the Agency's five-step "top-down" BACT process to determine BACT for PSD permit applications in general. Though TCEQ's "three-tiered" approach is considered equivalent to top-down, BACT discussed in this application is in top- down form for GHG pollutants. In brief, the top-down process calls for all available control technologies for a given pollutant to be identified and ranked in descending order of control effectiveness. The permit applicant should first examine the highest-ranked ("top") option. The top-ranked options should be established as BACT unless the permit applicant demonstrates to the satisfaction of the permitting authority that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the top ranked technology is not "achievable" in that case. If the most effective control strategy is eliminated in this fashion, then the next most effective alternative should be evaluated, and so on, until an option is selected as BACT. The five basic steps of a top-down BACT analysis are listed below:

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

The first step is to identify potentially "available" control options for each type of source subject to BACT review, for each pollutant under review. Available options should consist of a comprehensive list of those technologies with a potentially practical application to the emission unit in question. For this analysis, the following sources are typically consulted when identifying potential technologies:

- USEPA's RACT/BACT/LAER Clearinghouse (RBLC) Database;
- Other recently submitted GHG permit applications that are associated with similar process types; and
- Engineering experience with similar control applications.

After identifying potential technologies, the second step in the BACT analysis is to eliminate technically infeasible options from further consideration. To be considered feasible, a technology must have been demonstrated or, if not, be both available and applicable. A control technology or process is only considered available if it has reached the licensing and commercial sales phase of development and is commercially available. To be considered applicable, it must be reasonable for the control technology to be installed and operated on the source type.

The third step is to rank the technologies not eliminated in Step 2 in order of descending control effectiveness for each pollutant of concern.

The fourth step entails an evaluation of energy, environmental, and economic impacts for determining a final level of control. The evaluation begins with the most stringent control option and continues until a technology under consideration cannot be eliminated based on adverse energy, environmental, or economic impacts.

The fifth and final step is to select as BACT the most effective of the remaining technologies under consideration for each pollutant of concern.

The BACT analysis contained in this application satisfies both TCEQ and EPA BACT requirements. Presented below are the five basic steps of a top-down BACT review as identified by EPA. Each step is conducted below for the sources subject to GHG BACT review.

6.2 Boilers

The Gulf Coast Growth Venture Project will include three steam boilers in the Utilities area that burn a mix of natural gas, blend gas, and vent gas. The boilers will emit three GHGs: CH_4, CO_2, and N_2O. CO_2 will be emitted from these sources because it is a combustion product of any carbon-containing fuel. CH_4 will be emitted from these sources as a result of any incomplete combustion of petrochemical facility fuel gas and/or natural gas. N_2O will be emitted from these sources in trace quantities due to partial oxidation of nitrogen in the air which is used as the oxygen source for the combustion process. The control technology discussion for boilers will primarily address control of CO_2 because emissions of CH_4 and N_2O are negligible relative to the emissions of CO_2. Because boilers and process heaters have many similar BACT considerations, the furnaces discussion in Section 6.6 will refer to several sections of the boiler BACT discussed in this section.

All fossil fuels contain carbon, but the fuel combusted in these boilers will be a low carbon fuel. Tail gas, the fuel produced in the Olefins unit is generally similar to natural gas but contains less methane and more hydrogen than natural gas does. In the combustion of a fossil fuel, the fuel carbon is oxidized into CO and CO_2. Full oxidation of fuel carbon to CO_2 is desirable because CO has long been a regulated pollutant with established adverse environmental impacts, and because full combustion releases more useful energy within the process. In addition, emitted CO is gradually oxidized to CO_2 in the atmosphere. CO_2 emissions are generated and emitted from the new boilers, and exhausted to the atmosphere from the flue gas stacks.

In addition to the guidances discussed in Section 6.1, the following EPA BACT GHG documents were also used to identify potential control technologies and work practices:

- Energy Efficiency Improvement and Cost Saving Opportunities for Petroleum Refineries: An ENERGY STAR Guide for Energy Plant Managers. Document Number LBNL-56183, February 2005;
- Available and Emerging Technologies for Reducing Green House Gas (GHG) emissions from the Petroleum Refining Industry, EPA, October 2010;
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boilers, EPA, October 2010;
- Report of the Interagency Task Force on Carbon Capture and Storage, August 2010; and
- RBLC database query of GHG BACT determinations related to petroleum refineries.

A BACT analysis for $CO_{2}e$ emissions from the boilers is presented in the following steps.

6.2.1 Step 1 – Identify CO_2e Control Technologies

The following technologies were identified as $CO_{2}e$ control options for the new boilers based on available information and data sources:

- Carbon Capture and Storage ([CCS], CO_2 control only);
- Use of low carbon fuels;
- Use of good combustion practices; and
- Energy efficient design.

6.2.1.1 *CCS*

CCS is a technique that captures CO_2 before the gas enters the atmosphere, compresses the concentrated CO_2, transports the CO_2 via pipeline to a site for injection, and stores CO_2 in an adequate geological formation. Potential geological formations for storage include depleted oil and gas fields, un-mineable coal formations, underground saline formations, or the deep ocean. Integrated facilities for CO_2 capture, transport, and storage for combustion exhaust have not been demonstrated for any petrochemical facility globally. In the United States a handful of integrated CCS systems have been planned as pilot projects, all of which have received significant government funding.

There are a number of methods and processes that could be used to capture CO_2 post combustion from the dilute exhaust gases produced by the boilers. These capture technologies include separation with solvent or physical filters, cryogenic separation to condense the CO_2, and membrane separation technologies.

6.2.1.1.1 Separation with Solvent Scrubbers

There are many solvents under development for the separation of CO_2 from combustion of flue gases through chemical absorption. The most commercially developed of these processes use monoethanolamine (MEA) as the solvent. MEA has the advantage of fast reaction with CO_2 at low partial pressure. The primary concern with MEA is corrosion in the presence of O_2 and other impurities, high solvent degradation rates due to reactions with SO_2 and NOx, and the energy requirements for solvent regeneration.

Diethanolamine (DEA) is another solvent available for CO_2 removal. While some research shows that slightly lower CO_2 overheads can be achieved with DEA relative to MEA, the same problems with corrosion and high degradation rates exist, in addition to foaming tendencies. Another commercially available solvent is methyldiethanolamine (MDEA), which offers advantages over MEA and DEA, such as low corrosion, slow degradation rates, low amine reboiler duty, reduced solvent losses, and low circulation demand. However, its slow reaction rate for CO_2 makes it impractical when removal of large amounts of CO_2 is desired, such as with the heaters in this application.

6.2.1.1.2 Cryogenic Separation

The cryogenic CO_2 capture process includes the following steps:

- Dry and cool the combustion flue gas;
- Compress the flue gas;
- Further cool the compressed flue gas by expansion which precipitates the CO_2 as a solid;
- Pressurize the CO_2 to a liquid; and
- Reheat the CO_2 and remaining flue gas by cooling the incoming flue gases.

The final result is the CO_2 in a liquid phase and a gaseous nitrogen stream that can be vented through a gas turbine for power generation. The CO_2 capture efficiency depends primarily on the pressure and temperature at the end of the expansion process. However, this process has not been commercially demonstrated on gas streams with low CO_2 concentrations such as the boilers at the petrochemical facility.

6.2.1.1.3 Membrane Separation

This method is commonly used for CO_2 removal from natural gas at high pressure and high CO_2 concentration. Membrane-based capture uses permeable or semi-permeable materials that allow for selective transport/separation of CO_2 from flue gas. It has been estimated that 80 percent of the CO_2 could be captured using this technology. The captured CO_2 would then be purified and compressed for transport. Membrane technology is not fully developed for CO_2 concentration and gas flow to process heaters at a petrochemical facility.

6.2.1.1.4 Carbon Transport and Storage

Following capture, CO_2 disposition at a sequestration reservoir or enhanced oil recovery (EOR) operation would have to be accommodated by pipeline transport. There are compression requirements to transport CO_2 in its "supercritical state," and purification requirements to remove water and prevent damage to the infrastructure from carbonic acid formation.

6.2.1.2 *Low Carbon Fuels*

Table 6-1 in this section presents the amount of CO_2 formed when combusting fossil fuels, including fuel gas which will be used by the new boilers. Tail gas, a special type of fuel gas, has a lower annual carbon content than natural gas. The boilers will use a fuel that is a combination of tail gas and natural gas. This gas is referred to as "blend gas" in this application. Additionally, vent gas of suitable heating value and stability will be routed to the boilers and reduce the amount of natural gas and blend gas needed for the boilers.

Table 6-1 CO2 Emission Factors

Fuel Type	**Default CO_2 Emission Factor**
Coal and coke	kg CO_2/mmBtu
Anthracite	103.69
Bituminous	93.28
Subbituminous	97.17
Lignite	97.72
Coal Coke	113.67
Mixed (Commercial sector)	94.27
Mixed (Industrial coking)	93.9
Mixed (Industrial sector)	94.67
Mixed (Electric Power)	95.52
Natural gas	kg CO_2/mmBtu
(Weighted U.S. Average)	53.06
Petroleum products	kg CO_2/mmBtu
Distillate Fuel Oil No. 1	73.25
Distillate Fuel Oil No. 2	73.96
Distillate Fuel Oil No. 4	75.04
Residual Fuel Oil No. 5	72.93
Residual Fuel Oil No. 6	75.1
Used Oil	74
Kerosene	75.2
Liquefied petroleum gases	61.71
Propane	62.87
Propylene	67.77

Table 6-1 CO_2 Emission Factors

(Continued from previous page)

Fuel Type	Default CO_2 Emission Factor
Ethane	59.6
Ethanol	68.44
Ethylene	65.96
Isobutane	64.94
Isobutylene	68.86
Butane	64.77
Butylene	68.72
Naphtha (<401 deg F)	68.02
Natural Gasoline	66.88
Other Oil (>401 deg F)	76.22
Pentanes Plus	70.02
Petrochemical Feedstocks	71.02
Petroleum Coke	102.41
Special Naphtha	72.34
Unfinished Oils	74.54
Heavy Gas Oils	74.92
Lubricants	74.27
Motor Gasoline	70.22
Aviation Gasoline	69.25
Kerosene-Type Jet Fuel	72.22
Asphalt and Road Oil	75.36
Crude Oil	74.54
Other fuels—solid	kg CO_2/mmBtu
Municipal Solid Waste	90.7
Tires	85.97
Plastics	75
Petroleum Coke	102.41
Other fuels—gaseous	kg CO_2/mmBtu
Blast Furnace Gas	274.32
Coke Oven Gas	46.85
Propane Gas	61.46

Table 6-1 CO2 Emission Factors

(Continued from previous page)

Fuel Type	Default CO_2 Emission Factor
Fuel Gas	59
Biomass fuels—solid	kg CO_2/mmBtu
Wood and Wood Residuals	93.8
Agricultural Byproducts	118.17
Peat	111.84
Solid Byproducts	105.51
Biomass fuels—gaseous	kg CO_2/mmBtu
Landfill Gas	52.07
Other Biomass Gases	52.07
Biomass Fuels—Liquid	kg CO_2/mmBtu
Ethanol	68.44
Biodiesel (100%)	73.84
Rendered Animal Fat	71.06
Vegetable Oil	81.55

[1]Obtained from 40 CFR Part 98, Subpart C, Table C-1.

As shown in the table above, the use of fuel gas reduces the production of CO_2 from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

The following table presents the default emission factors of CH_4 and/or N_2O formed when combusting fossil fuels, including some of the fuels that will be used by the new boilers.

Table 6-2 CH_4 and N_2O Emission Factors[2]

Fuel Type	Default CH_4 Emission Factor (kg CH_4/MMBtu)	Default N_2O Emission Factor (kg N_2O /MMBtu)
Coal and Coke (All types in Table C–1)	1.1×10^{-02}	1.6×10^{-03}
Natural Gas	1.0×10^{-03}	1.0×10^{-04}
Petroleum (All types in Table C–1)	3.0×10^{-03}	6.0×10^{-04}
Fuel Gas	3.0×10^{-03}	6.0×10^{-04}
Municipal Solid Waste	3.2×10^{-02}	4.2×10^{-03}

Table 6-2 CH_4 and N_2O Emission Factors

(Continued from previous page)

Fuel Type	Default CH_4 Emission Factor (kg CH_4/MMBtu)	Default N_2O Emission Factor (kg N_2O /MMBtu)
Tires	3.2×10^{-02}	4.2×10^{-03}
Blast Furnace Gas	2.2×10^{-05}	1.0×10^{-04}
Coke Oven Gas	4.8×10^{-04}	1.0×10^{-04}
Biomass Fuels-Solid (All types in Table	3.2×10^{-02}	4.2×10^{-03}
Biogas	3.2×10^{-03}	6.3×10^{-04}
Biomass Fuels-Liquid (All types in Table	1.1×10^{-03}	1.1×10^{-04}

[2]*Obtained from 40CFR98, Subpart C, Table C-2.*

As shown in the table, the use of petrochemical facility fuel gas reduces the production of CH_4 and N_2O from combustion of fuel relative to burning solid fuels (e.g. coal or coke) and liquid fuels (i.e., distillate or residual oils).

6.2.1.3 *Good Combustion Practices*

Efficient combustion is one of the most effective means of minimizing GHG emissions from combustion sources such as the boilers for this project. GHG emission reductions are achieved by maximizing the amount of product that is produced per unit of fuel. Efficient combustion is achieved by implementing good combustion practices which include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone;
- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;
- Implementing a maintenance program to monitor fouling conditions in the subject boilers;
- Tune-up program including CO optimization and flame pattern inspection; and

- Heat recovery for steam generation.

Combustion efficiency is related to the three "T's" of combustion: time, temperature, and turbulence. These components of combustion efficiency are designed into the new boilers to maximize fuel efficiency and reduce operating costs. Therefore, combustion control is accomplished primarily through boiler design and operation. Combustion practices which reduce CH_4 emissions through increased combustion efficiency but simultaneously diminish energy efficiency, such as the use of high excess oxygen levels in the combustor which leads to increased overall GHG emissions, are not considered GHG control options.

6.2.1.4 *Energy Efficient Design*

Energy efficiency is a highly effective means of controlling CO_2 emissions. A more energy-efficient technology burns less fuel than a less energy efficient technology on a per-unit-of-output basis. Every unit of energy saved at the point of consumption through efficiency is a unit of energy that need never be produced or transmitted, and that never creates emissions. Energy efficient technologies also help reduce the production of combustion-related GHG and other regulated pollutants (CO, NOx, PM/PM_{10}/$PM_{2.5}$, SOx and VOC). EPA has recognized that BACT emission limits for GHGs will often be based on energy efficiency since the use of add-on controls to reduce GHG emissions is not as well-advanced as it is for most combustion-derived pollutants. As a result, the EPA has stated that the utilization of methods, designs, or techniques to maximize energy efficiency is a key GHG reducing opportunity.

EPA's GHG guidance also states that it is important in BACT reviews for permitting authorities to consider options that improve the overall energy efficiency of the entire source through use of efficient technologies, processes and practices at each emitting unit. In some instances, a more efficient process may be effectively used by itself; while in other cases, an efficiency measure may be used to supplement additional control of criteria pollutants.

The GHG PSD Guidance recognizes two categories of energy efficient options that should be considered in Step 1 of a GHG BACT analysis. The first category of energy efficiency options evaluates the efficiency of an individual emissions unit. For individual unit efficiency, the proposed unit's heat input, or energy that is used in the process should be reviewed.

Energy efficiency is inherent to modern boiler design, which includes carefully engineered heat exchanger trains that transfer heat between various process streams to minimize need for additional heat input.

For boilers, the use of the following can provide opportunities for minimizing the required fuel combustion for boilers and process heaters:

- Combustion air preheat;
- Use of process heat to generate steam;
- Process integration and heat recovery.

6.2.2 Step 2 – Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates any control technology that is not considered technically feasible unless it is both available and applicable.

6.2.2.1 *CCS*

As referenced in the March 2011 GHG Title V and PSD permitting guidance (Document No. EPA457/B11-001), EPA has identified CCS as an available add-on control technology that should be evaluated.

6.2.2.1.1 Separation with Solvent Scrubbers

Solvent scrubbing has been used in the chemical industry for separation of CO_2 in exhaust streams and is a technically feasible technology for this application; however, it has not been demonstrated in large scale industrial process applications that do not have high-purity CO_2 streams. GCGV does not believe using solvent scrubbing with MEA, DEA or MDEA is a technically feasible technology for this application, but will assume solvent scrubbing with MEA in the analysis in Section 6.2.4.1 because it is the most commercially available.

6.2.2.1.2 Cryogenic Separation

Due to the low concentration of exhaust CO_2 from conventional air-based combustion devices such as the process heaters in the project, this technology is considered technically infeasible.

6.2.2.1.3 Membrane Separation

Due to the low concentration of exhaust CO_2 from conventional air-based combustion devices such as the process heaters in the project, this technology is considered technically infeasible.

6.2.2.1.4 Carbon Transport and Storage

An integrated CCS application is technically infeasible due to the short-term and long-term uncertainty and risks surrounding the design, installation, and operation of a CCS project; the dependence upon a third party commercial contract for CO_2 disposition, i.e., enhanced oil recovery (EOR); and the absence of a regulatory infrastructure to oversee and regulate long- term CO_2 storage.

These risks are not unique to the proposed project. The Interagency Task Force Report highlights the general short and long term CCS regulatory and market demand uncertainties.

1. The existence of market failures, particularly the lack of a cohesive climate policy setting a price on carbon and encouraging emission reductions.
2. The need for a legal and regulatory framework for CCS projects that facilitates project development, protects human health and the environment, and

addresses public concerns whether CO_2 can be stored safely and securely.

3. Improved industry confidence regarding the long-term liability for CO_2 storage, particularly regarding obligations for stewardship after closure and obligations to compensate parties for various types and forms of legally compensable losses or damages.
4. Integration of public information, education, and outreach throughout the CCS project lifecycle in order to foster public understanding and to build trust between communities and project developers.

The 2011 EPA GHG PSD Guidance also reiterated the regulatory, financial and technical challenges associated with CCS and recognized that a permitting authority will conclude that CCS is technically infeasible.

The factors supporting technical infeasibility of an integrated CCS system are described further below.

Capture from the Boilers

There are technical issues which would prohibit the successful application of CCS to the project boilers. As a threshold matter, there is no commercial demonstration of capturing and purifying CO_2 from fuel gas streams where the content is less than 10%. CO_2 must be captured and processed to produce a high pressure, high purity product stream suitable for delivery to storage or an enhanced oil recovery project. While the technology for the post-combustion capture of CO_2 may be available at small scale, the process has not been demonstrated at the scale required for the project boilers. GCGV was unable to find an example of CO_2 capture and storage from petrochemical facility boilers after a thorough search of literature, existing permit applications and approvals and the GHG RBLC database. EPA has referenced a Nuevo Midstream, Ramsey Gas Plant application from November 2014 that identified CCS as BACT. The arrangements made around that agreement are highly unusual for the disposal of pollution. The location of the gas plant in relation to a CO_2 pipeline (within a few hundred feet) significantly reduced the cost and logistical implications of connecting and utilizing the disposal method.

At present time, these necessary elements for CCS are either in an early stage of knowledge and/or implementation, and as such, are not mature enough to allow for large scale commercial deployment of the storage aspects of CCS. As a result, the known technology gap to identify secure storage formations, lack of a fiscal framework for financing the costs of a CCS project, and the lack of regulatory framework (such as a defined long term liability provisions) increase overall project technical and financial risk which at this time still presents significant barriers to private sector implementation of commercial scale CCS.

Enhanced Oil Recovery

EOR is a process where CO_2 is injected into a reservoir to increase the total recovery of oil remaining in a reservoir after the primary and secondary recovery production stages in the field. Existing CO_2-EOR uses CO_2 that is produced from naturally occurring subsurface geologic formations. While CO_2-EOR has been practiced by the oil and gas industry for several decades, the injection of CO_2 ceases once the economic threshold for the increased recovery of oil has been reached. Significantly for this CCS BACT review, the long-term CO_2 storage following EOR has not been tested on a large industry wide commercial scale.

Currently the Denbury CO_2 Green Pipeline is located approximately 170 miles from the project location. There are no existing or planned connecting pipelines for anthropogenic sources of CO_2 to Denbury; therefore, any new pipelines required would be at a significant cost to the project. Additionally, commercial markets for anthropogenic CO_2 sales are undeveloped and provide little to no regulatory certainty that the project will be able to comply with any potential CO_2 permit limit imposed due to CCS like was the case in the Nuevo Midstream BACT determination. Long-term CO_2 disposition at the project location could be hampered by the lack of certainty of local EOR demand for CO_2 and potential time lag as mature oil fields need to be prepared for EOR and new pipelines developed for delivery.

Local Geological Storage Sites

The lack of long term, proven geologic storage sites for CO_2 is also a technological barrier. While there are salt dome caverns along the Gulf Coast, these limestone formations have not been demonstrated to safely store acid gases such as CO_2, nor is there confirmed adequate availability of space. Instead, these domes are used for cyclical storage of liquefied petroleum gases (LPGs) for use in the Gulf Coast as well as for shipment throughout the United States via pipeline.

6.2.2.2 *Lower Carbon Fuels*

The project boilers will combust blend gas, natural gas, and vents which are low-carbon fuels. Blend gas is a mixture of the smallest molecules produced from cracking (methane and hydrogen) mixed with natural gas (primarily methane). The use of blend gas in the boilers reduces CO_2 formation below natural gas. The use of vent gas reduces the amount of purchased natural gas needed at the facility. Thus, the use of blend gas with lower carbons than natural gas is technically feasible and is inherent in the design of the new boilers.

6.2.2.3 *Good Combustion Practices*

Excessive amounts of combustion air used in process heaters result in inefficiencies because more fuel combustion is required to heat the unnecessary air to combustion temperatures.

This can be alleviated by using instrumentation for monitoring and controlling the excess air levels in the combustion process. The result is a reduction in the heat input because the amount of combustion air needed for safe and efficient combustion is minimized. This requires the installation of oxygen monitors in the boiler and damper controls on the combustion air dampers. Lowering excess air levels, while maintaining good combustion, reduces CO_2 as well as NOx emissions. Good combustion practices for boilers fired with petrochemical facility fuel gas are technically feasible and are inherent in the design of the new boilers.

6.2.2.4 *Energy Efficiency*

For an integrated petrochemical facility, there are several ways to improve energy efficiency, as identified previously.

Combustion air preheat is a method of recovering heat from the hot combustion exhaust gas by heat exchange with the combustion air before it enters the combustion chamber of the boiler. Preheating the combustion air reduces the amount of fuel required in a boiler because the combustion air does not have to be heated from ambient temperature to the fuel combustion temperature by combusting fuel. This heat recovery approach is commonly used on large process heaters and boilers. To equip a heater with air preheat requires maintenance costs. For heaters of sufficient size these costs are offset by the fuel savings. Although combustion air preheat reduces the amount of CO_2 emitted, the project will not include air preheat due to the thermal NOx emissions increase that preheating the combustion air would cause.

Process fluid preheat is a method of recovering heat from the hot combustion flue gas emitted by boiler through heat exchange with the process fluid. Preheating of process fluids reduces the amount of fuel required by the process heater. Systems used to preheat the process fluid are referred to as economizers. Noncondensing economizers are more common than condensing economizers because they do not require the use of special metallurgy and draft fans. Boiler feedwater pre-heat will be provided by the use of economizers.

The use of process integration and heat recovery as a result of these design features will result in a reduction in stack temperature.

6.2.3 Step 3 – Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the project heaters based on available information and data sources:

- Use of low carbon fuels (control efficiency is not available);
- Use of good combustion practices (control efficiency is not available); and
- Energy efficient design (control efficiency is not available).

Notwithstanding the arguments presented in this analysis and determinations from similar projects, the following CO_2 control options for the boilers will be considered technically feasible for the purpose of advancing the option to Step 4:

- CCS (typically assumed at 90% control efficiency).

6.2.4 Step 4 – Evaluate the Most Effective Controls and Document Results

6.2.4.1 *Carbon Capture Systems*

For the purposes of the following analysis of post-combustion CCS, chemical absorption using MEA based solvents is assumed to represent the best post-combustion CO_2 capture option. This control option is assumed to be 90 percent effective. The analysis conservatively assumes that flue gases from all boilers and furnaces would be controlled. The combined CO_2 emission rate of captured CO_2 from the new boilers and the new furnaces is 2,009,098 tpy. The CO_2 rich solvent from the scrubber would then be pumped to a regeneration system for CO_2 removal and reuse. The CO_2 would need to be dried, compressed from low pressure up to 2,000 psi and transported by pipeline to an appropriate storage site.

Pipeline transportation and injection/storage costs are estimated to be $1.5 - $23 per tonne CO_2. Costs are highly dependent on distance to nearest available carbon storage facility, terrain the pipeline must pass through, type of storage reservoir, existing infrastructure, regional factors, etc. In addition, adding the CCS would result in some energy penalty of up to 15% simply because the CCS process will use steam produced by the facility resulting in a loss of efficiency which may in turn potentially increase the natural gas fuel use of the facility to overcome these efficiency losses.

In this submittal, the costs associated with pipeline transport of CO_2 post-capture are estimated using the March 2010 National Energy Technology Laboratory (NETL) document "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447"[1]. The calculations of estimated costs associated with materials, labor, indirect costs and right of way acquisition were based on functions of pipeline diameters and lengths that were determined as appropriate for the site. The nearest CO_2 delivery line to the petrochemical facility is the Denbury Pipeline, which is assumed to be an achievable connection roughly 170 miles away, straight line distance. The company that owns the pipeline may be a competitor ; therefore, the 170-mile dimension in the calculations could actually be greater.

Assuming the Denbury Pipeline could receive effluent from the project's amine system, and including additional costs associated with compression, amine scrubbing, surge protection and pipeline control, the total cost is estimated to be over $1,220,000,000 or $63.74/ton CO_2 removed.

Due to the extraordinary capital costs of implementing post-combustion CCS at the petrochemical facility, it is considered a technically infeasible and economically unreasonable control option, and is not selected in the 5-step top down BACT analysis. See Table 6-6a at the end of this section for a detailed breakdown of the estimated costs. In addition to these costs, the use of CCS for new boilers at the project would entail significant adverse energy and environmental impacts due to increased fuel usage in order to meet the steam and electric load requirements of these systems. In order to capture, dry, compress, and transport to a suitable EOR site, the CO_2 available for capture from the process heaters would require excessive

[1] "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447", The US Department of Energy and National Energy Technology Laboratory, 2010.

amounts of additional electric power and steam generation capacity. The generation of the steam and electric power required by the project would itself result in GHG emissions, which would offset some if not all of the net GHG reduction achieved by capturing and storing the CO_2 emitted by the new process heaters.

These adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CCS. Therefore, CCS does not represent BACT for the boilers associated with this project.

6.2.4.2 *Use of Low Carbon Fuels, Good Combustion Practices, and Energy Efficient Design*

The use of low carbon fuels and good combustion practices are inherent in the design and operation of the new boilers associated with this project.

Monitoring of flue gas temperature and excess oxygen, using vent gas burners maintainable online, and performing a tune-up according to the requirements in 40 CFR Part 63, Subpart DDDDD ("the Boiler MACT") will ensure that the boilers operate at high thermal efficiency.

In addition, the new boilers will be operated according to the manufacturer's specifications and monitoring will be consistent with the facility's GHG monitoring plan required by 40 CFR Part 98.

6.2.5 Step 5 – Selection of BACT

CCS does not represent BACT for new boilers because the adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO_2 capture for this project.

The project will incorporate the use of low carbon fuel (blend gas, natural gas, or vent gas), good combustion practices and energy efficient design where possible for the new boilers to meet BACT. BACT performance will be demonstrated through excess oxygen and temperature monitoring in the stack flue gases.

6.3 Engines

Several engines will be provided in the project for electric generation during emergency situations and to drive water pumps for firefighting purposes. The engines will have less than 10 liters' displacement per cylinder and fire diesel fuel. They will not operate continuously, but on unplanned intervals called for by emergency situations and short, regular intervals to ensure that the engines are ready when needed.

6.3.1 Step 1 – Identify CO_2e Control Technologies

The following potential GHG control strategies for engines were considered as part of this BACT analysis:

- Good Design;

- Frequency of Usage;
- Fuel Selection; and
- Best Operational Practices.

6.3.1.1 *Good Design*

Advances in modern engine design are reflected in the emission limits applicable to manufacturers through tiered standards in the Code of Federal Regulations. The engines planned for the project will be certified to NSPS and MACT emission limits. This ensures that fossil fuels consumed in the engines will be efficiently combusted and pursuant generation of greenhouse gases thus minimized.

6.3.1.2 *Frequency of Usage*

While the design and manufacture of the engine ultimately determines the amount of greenhouse gas that will be generated by the engine during its operation, the annual GHG emission rate will be determined by annual usage, often estimated in number of hours per year. Because the project will use electric motors for pumps and compressors needed throughout processes at the facility, the combustion engines proposed are for emergency use only. The annual planned and thus permitted usage is limited to periodic testing required in fire codes and manufacturer recommendation.

6.3.1.3 *Fuel Selection*

As discussed previously in this analysis, the use of a low carbon fuel such as natural gas or blend fuel gas will result in lower GHG emissions than liquid fuels such as diesel. However, diesel fuel will be used, since gaseous fuel may be unavailable for the engines during emergency situations.

6.3.1.4 *Best Operating Practices*

During operation proper mixing of air and fuel will be ensured to prevent visible emissions, uncombusted fuel and unnecessary GHG emissions. To ensure the engines operate properly a maintenance program will be instituted for the engines including:

- Change oil and filter every 500 hours of operation or annually, whichever occurs first;
- Inspect air cleaner every 1,000 hours of operation or annually, whichever occurs first;
- Inspect all hoses and belts every 500 hours of operation or annually, whichever occurs first, and replace as necessary.

6.3.2 Step 2 – Eliminate Technically Infeasible Options

All control technologies identified in Section 6.3.1 are considered technically feasible, except that the use of gaseous fuels is infeasible as one of the emergency situations that may arise is unavailability of facility natural gas. Diesel fuel can be safely transported and stored.

6.3.3 Step 3 – Rank Remaining Control Technologies

Good engine design, frequency of usage, and best operational practices are the most effective options for control.

6.3.4 Step 4 – Evaluate the Most Effective Controls and Document Results

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.3.5 Step 5 – Selection of BACT

The project will include engines designed and certified to recent CFR standards, operate the engines only as necessary to assure their readiness, and operate and maintain the engines according a program at the facility which complies with 40 CFR Part 63, Subpart ZZZZ and 40 CFR Part 60, Subpart IIII. BACT performance will be demonstrated through meeting annual run time limitations, and compliance with GHG annual mass rate (tpy) emission limits.

6.4 Flares

Three flares will be provided in the project to provide safe and efficient disposal of vent streams such as:

- Manufacturing losses from compressor seals, bed regenerations, exchanger swaps, valve leakage, etc.;
- Intermittent flows from startup, shutdown, and grade changes;
- Purges before performing maintenance to ensure good condition of equipment; and
- Storage emissions from some tanks.

CO_2 and N_2O emissions from flaring process gas are produced from the combustion of carbon containing compounds (e.g., CO, VOCs, CH_4) present in the process gas streams, supplemental fuel, sweep gas, and the pilot fuel. GHG emissions from the flares are based on the estimated flow rates of CO_2 and flared carbon-containing gases derived from heat and material balance data.

The flare is an example of a control device in which the control of certain pollutants causes the formation of collateral GHG emissions. Specifically, the control of CH_4 in the process gas at the flare results in the creation of additional CO_2 emissions via the combustion reaction mechanism. However, given the relative GWPs of CO_2 and CH_4 and the destruction of VOCs and HAPs, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.

6.4.1 Step 1 – Identify $CO_{2}e$ Control Technologies

The following potential GHG control strategies for the flare were considered as part of this BACT analysis:

- Good Process Design;
- Good Flare Design;
- Flare Gas Recovery (FGR); and
- Best Operational Practices.

6.4.1.1 *Good Process Design*

The recovery of gases with useful properties is inherent to the design of the facility. These properties include:

- Heating value; and
- Stability of the stream.

Tail gas from the demethanizer chilling step has some heat value provided by the methane and hydrogen content, and is a continuous stream provided at a manageable pressure. Consequently, this stream will be used as fuel gas in the furnaces and boilers. Polyethylene continuous vent streams are also useful as fuel and will be used by the boilers. Intermittent streams generated from olefins and other process units are not as well suited for fuel and are less favorable to use as fuel.

In addition to streams used as fuel, process recovery will be implemented in various areas to recover molecules usable to produce additional product like ethane, ethylene, and monomers in the Olefins, Glycol, and PE units, respectively.

Returning gases to the process reduces the amount of gas combusted in flares and thus minimizes GHG emissions.

6.4.1.2 *Good Flare Design*

Good flare design can be employed to destroy large fractions of the flare gas. Modern flare and flare tip design has evolved to assure high reliability and destruction efficiencies. Lower pressure and/or lower heating value streams will be preferentially routed to the elevated flare to reduce the amount of supplemental fuel necessary to ensure a good destruction efficiency. The flares will be designed to achieve 99% destruction efficiency for compounds with one to three carbons.

6.4.1.3 *Flare Gas Recovery (FGR)*

FGR is a technology that emerged from the drive to reduce flared gas streams at existing large integrated refineries. One type of FGR system includes the addition of water seal drums to prevent recoverable gas flow to the flare while allowing the flare to function in the event of an emergency and control larger routine flows. A compressor located on the downstream end of the main flare header is used to increase the pressure of a volumetric flow of flare gas, allowing it to reach a facility that can beneficially use the flare gas as fuel. For the purposes of this application, FGR is a system that routes vents usable as fuel to the boilers. Through good process design, tailgas will be used with natural gas in the furnaces and boilers, and other streams with sufficient heating value and stability will be routed to the boilers.

6.4.1.4 *Best Operational Practices*

Best Operational Practices for the flare include pilot flame monitoring, flow measurement, and monitoring/control of vent gas heating value to ensure flame stability in accordance with 40 CFR §60.18 when vent gas is directed to the flare. The heat value of the vent gas will be supplemented by the addition of natural gas and/or ethane to assure a minimum heating value in compliance with 40 CFR §60.18 for elevated flares, and a substantially higher value for ground flares. The exit velocity of elevated flares will be maintained within §60.18 limitations. Multi-point ground flares are designed according to a different theory of operation which utilizes pressure in the vent gas for flame stability, which has been acknowledged in recent state and federal approvals of ground flare exceptions to the maximum §60.18 exit velocity limitation[2]. Low carbon supplemental fuel will be added when needed to assure safe operation of the flare systems and proper combustion. These are best management practices are employed to minimize the amount of uncombusted CH_4 from natural gas as well as CO_2 from the combustion of CH_4.

6.4.2 Step 2 – Eliminate Technically Infeasible Options

All control technologies identified in Section 6.4.1 are considered technically feasible.

6.4.3 Step 3 – Rank Remaining Control Technologies

Good process design, good flare design, best operational practices, and the routing of appropriate vents to fuel are the most effective options for control.

6.4.4 Step 4 – Evaluate the Most Effective Controls and Document Results

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.4.5 Step 5 – Selection of BACT

GCGV will use good process design, good flare design, best operational practices, and the routing of appropriate vents to fuel as best available control options for reducing GHGs emitted from the flares. BACT performance will be demonstrated through compliance with the operational requirements in §60.18/approved alternative, and compliance with GHG annual mass rate (tpy) emission limits.

[2] EPA Alternative Means of Emission Limitation (AMEL) approval for Dow Chemicals and ExxonMobil at 81 FR 23480, as well as a variety of TCEQ-issued Alternative Means of Control (AMOC) letters.

6.5 Fugitives Components – GHG BACT

The Gulf Coast Growth Venture Project will include new piping including pumps, valves, and connectors for movement of gas and liquid raw materials, intermediates, and feed stocks. These components are potential sources of CH_4 emissions due to leakage from rotary shaft seals, connection interfaces, valve stems, and similar points.

6.5.1 Step 1 – Identify CO_2e Control Technologies

The identified available control technologies for process fugitive emissions of methane are as follows:

- Installation of leakless technology components;
- Instrumented Leak Detection (Method 21) and Repair Program;
- Leak detection and repair program utilizing remote sensing technology;
- Implementing audio/visual/olfactory leak detection methods; and
- Implementing lower leak detection level for components.

6.5.2 Step 2 – Eliminate Technically Infeasible Options

6.5.2.1 *Leakless Technology Components*

Leakless technology is available and in use in industry. It includes leakless valves and sealless pumps and compressors. Common leakless valves include bellows valves and diaphragm valves; and common sealless pumps are diaphragm pumps, canned motor pumps, and magnetic drive pumps. Leaks from pumps can also be reduced by using dual seals with or without barrier fluid. In addition, welded connections in lieu of flanged or screwed connections may provide for leakless operation. This technology is considered technically feasible.

6.5.2.2 *Instrumented Leak Detection (Method 21) and Repair Program*

LDAR programs based on EPA Method 21 instrument monitoring for leak detection and repair provisions are viable for streams containing combustible gases, including methane. This technology is considered technically feasible.

6.5.2.3 *Leak Detection and Repair Program Utilizing Remote Sensing Technology*

Remote sensing of leaks has been proven as a technology using infrared cameras. The use of these devices has been approved by the EPA as an alternative to EPA Method 21 in certain instances. The remote sensing technology can detect methane emissions. Therefore, this technology is considered technically feasible.

6.5.2.4 *Implementing Audio/Visual/Olfactory (AVO) Leak Detection Methods*

AVO methods of leak detection are considered technically feasible.

6.5.2.5 *Implementing Lower Leak Detection Level for Components*

Lower leak detection levels for components are typically utilized/implemented under consent decrees issued by the EPA in order to minimize leak frequency and severity. This technology is considered technically feasible.

6.5.3 Step 3 – Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for methane control options for fugitive emissions components based on available information and data sources.

Table 6-3 Summary Fugitive BACT Technology Control Efficiencies

Technology	Control Efficiency (%)
Leakless Technology	100
Instrumented LDAR program (Method 21)	97
Remote Sensing Technology	>75
AVO Program	30
Lower Leak Detection Levels	Undefined

6.5.3.1 *Leakless Technology Components*

Leakless technologies should be nearly 100 % effective in eliminating leaks except when certain components of the technology suffer from a physical failure. These technologies do not, however, eliminate emissions at all leak interfaces, even when working as designed. Those interfaces are typically stationary interfaces and therefore leak frequency would be expected to be low. Following a failure of one of the essential elements of a component such as a valve stem or diaphragm, the component is likely to be non-repairable without a unit shutdown.

6.5.3.2 *Instrumented Leak Detection (Method 21) and Repair Program*

LDAR programs that are based on a quarterly EPA Method 21 monitoring of components with a leak definition of 500 ppmv are considered to have a control efficiency of 97 percent for the majority of components. The Texas 28VHP fugitive monitoring program requires all components (except connectors) to be monitored quarterly via EPA Method 21. Connectors are required to have a weekly AVO inspection. The leak definitions for the 28VHP program are similar to MACT Subpart H standards: 2000 ppmv for pumps and compressors and 500 ppmv for all other components. Table 6-5 summarizes the control efficiency and leak definition based on the type of component from TCEQ's "Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives."

Table 6-5 28VHP LDAR Program Control Efficiencies

Equipment	Leak Definition (ppmv)	Control Efficiency (%)
Valves (Gas/Vapor)	500	97
Valves (Light Liquid)	500	97
Flanges/Connectors	500	30
Pumps	2000	85
Compressors	2000	85
Relief Valves	500	97
Open-Ended Lines	500	7
Sampling Connections	500	97

6.5.3.3 *Remote Sensing Technology*

Remote sensing technology for detecting leaks has been approved by the EPA as an alternative to Method 21 monitoring under certain instances. Based on the equivalency to Method 21 monitoring, remote sensing technology is assumed to have no less than 75% control efficiency.

6.5.3.4 *Audio/Visual/Olfactory (AVO) Leak Detection Method*

The effectiveness of AVO methods of leak detection and repair are dependent on the system pressure and on odor of the process chemicals as well as the frequency of the AVO inspections. Several LDAR programs state components with a weekly AVO inspection have equivalent to 30% control efficiency.

6.5.3.5 *Lower Leak Detection Level for Components*

Using lower leak detection levels than those in current regulatory programs such as MACT or NSR programs are typically utilized/implemented under consent decrees issued by the EPA in order to minimize leak frequency and severity of leaks.

Control efficiencies associated with lower leak detection levels have not been defined.

6.5.4 Step 4 – Evaluate the Most Effective Controls and Document Results

6.5.4.1 *Leakless Technology Components*

While leakless technology components provide the highest level of control of the six technologies identified, they are not justified for components in methane service when considering the other control options available. Leakless technologies have not been universally adopted as LAER or BACT. They are also not required for toxic or hazardous services for components covered under the MACT programs. Therefore, it is reasonable to state that these technologies are unwarranted for control of methane with no acute impact. Any further consideration of available leakless technologies for GHG controls is unnecessary.

6.5.4.2 *Instrumented Leak Detection (Method 21) and Repair Program*

LDAR programs for instrumented detection of leaks have traditionally been developed and implemented for control of VOC emissions. BACT determinations related to equipment leaks in VOC service have been identified as an instrumented LDAR program. Although methane is not considered a VOC, it can be detected and quantified by using the same methods in EPA Method 21. Instrumented programs are widely implemented throughout the US for manufacturing sites.

GCGV proposes using the 28VHP LDAR with connector monitoring program to minimize GHGs measured as methane as during instrument monitoring. GCGV proposes to monitor equipment that contains a gas or liquid that is at least 10 percent by weight of VOC, consistent with the 28VHP Program.

6.5.4.3 *Remote Sensing Technology*

Remote sensing of fugitive components in methane service can provide an effective means to identify fugitive leaks. However, GCGV is requesting to use an instrumented LDAR program that has higher control efficiencies overall than remote sensing technology for this application. Therefore, this option is not considered BACT.

6.5.4.4 *Audio/Visual/Olfactory Leak Detection Methods*

Methane leaking components can be identified through AVO methods for odorized streams. However, GCGV is requesting to use an instrumented LDAR program that has higher control efficiencies overall than AVO.

6.5.5 Step 5 – Selection of BACT

GCGV proposes to use the 28VHP LDAR program for components in VOC service to monitor GHGs. BACT performance will be consistent with the 28VHP program.

6.6 Furnaces

The project will include eight process furnaces in the Olefins unit which create GHG emissions by the same mechanism as the boilers; however, the basic furnace design involves a box with many fired heaters along the floor or walls which transfer heat to tubes inside the box, and the basic boiler design involves fewer burners.

6.6.1 Step 1 – Identify CO_2e Control Technologies

The following technologies were identified as CO_2e control options for the process heaters:

- CCS (CO_2 control only);
- Use of low carbon fuels;
- Use of good combustion practices; and
- Energy efficient design.

6.6.1.1 *CCS*

Please refer to Section 6.2.2.1 for a discussion of CCS.

6.6.1.2 *Low Carbon Fuels*

Potential fuels for the furnaces include tail gas produced in the unit, natural gas received from offsite, or a blend of the two. Blend gas and natural gas are low carbon fuels. The use of blend gas for fuel reduces the facility's overall CO_2 emissions.

6.6.1.3 *Good Combustion Practices*

Efficient combustion is achieved by implementing good combustion practices which include the following:

- Good air/fuel mixing in the combustion zone;
- Sufficient residence time to complete combustion;
- Proper fuel gas supply system design and operation in order to minimize fluctuations in fuel gas quality;
- Good burner maintenance and operation;
- High temperatures and low oxygen levels in the primary combustion zone;
- Monitor oxygen levels and air intake to optimize the fuel/air ratio and minimize excess air;
- Up-to-date design maximizing surface area in the convection section;
- Condensate recovery system; and
- Heat recovery for steam generation.

6.6.1.4 *Energy Efficient Design*

When possible based on existing petrochemical facility design and operation, the use of the following can provide an energy efficient design for minimizing the required fuel combustion for furnaces.

- Combustion air preheat;

- Process integration and heat recovery;
- Use of newer burner with latest proven engineering design;
- Excess combustion air monitoring and control.

6.6.2 Step 2 – Eliminate Technically Infeasible Options

Combustion air preheat is considered technically infeasible for the same reasons identified in Sections 6.2.2.4.

6.6.3 Step 3 – Rank Remaining Control Technologies

The following technologies and control efficiencies were identified as technically feasible for CO_2 control options for the furnaces based on available information and data sources:

- Use of low carbon fuels (control efficiency is not available);
- Use of good combustion practices (control efficiency is not available); and
- Energy efficient design (control efficiency is not available).

Notwithstanding the arguments presented in this analysis and determinations from similar projects, the following CO_2 control options for the furnaces will be considered technically feasible for the purpose of advancing the option to Step 4:

- CCS (typically assumed at 90% control efficiency).

6.6.4 Step 4 – Evaluate the Most Effective Controls and Document Results

6.6.4.1 *CCS*

The cost discussion and estimates in Section 6.2.4.1 applies to a CCS control option for the furnaces because the same technological scenario of capturing stack gases, then separating, compressing and transporting CO_2 would be required for the boiler stack as would be required for a process heater stack.

6.6.4.2 *Use of Good Combustion Practices and Energy Efficient Design*

The use of good combustion practices is inherent in the design and operation of the furnaces. The furnaces will include an economizer and other energy efficiency design features where feasible.

Continuously monitored indicators will be used to ensure that the new furnaces will operate within optimum design parameters. These parameters include: fuel flow and stack O_2 and temperature. Other energy efficient designs will be incorporated as feasible.

In addition, the new furnaces will be operated according to the manufacturer's specifications and monitoring will be consistent with the facility's GHG monitoring plan required by 40 CFR Part 98.

6.6.5 Step 5 – Selection of BACT

CCS does not represent BACT for the furnaces because the adverse energy, environmental, and economic impacts are significant and outweigh the environmental benefit of CO_2 capture for this project.

The furnaces meet BACT through energy efficient design, low carbon fuels and good combustion practices. BACT performance will be demonstrated through excess oxygen and temperature monitoring in the stack flue gases.

6.7 Glycol Byproduct Vent

The Ethylene Oxide reactor produces CO_2 as a byproduct. It is stripped in a stripper and the stream with a high CO_2 concentration is normally routed to a T.O.; however, during limited annual periods of T.O. downtime the stream can be routed to the flare.

6.7.1 Step 1 – Identify $CO_{2}e$ Control Technologies

The following potential GHG control strategies for the byproduct vent were considered as part of this BACT analysis:

- CCS;
- Good Process Design; and
- Best Operational Practices.

6.7.1.1 *CCS*

Please refer to Section 6.2.2.1 for a discussion of CCS.

6.7.1.2 *Good Process Design*

Ethylene oxide (EO) is produced by reacting ethylene with oxygen in the presence of a catalyst. Competing with the primary EO reaction, an alternate reaction is the oxidation of ethylene to form CO_2 and water (instead of the desired EO product). Moreover, there is also a consecutive reaction where EO further reacts to form the end products of CO_2 and water. To minimize GHG emissions, catalyst selection, minimizing excess oxygen, and minimizing allowed reaction time are critical to maximize EO production while minimizing the competing and consecutive reactions to produce CO_2 and water. Further, the reaction to produce EO also yields heat which is used within the unit to reduce reliance on the Utilities Boilers. Therefore, proper design is demonstrated via use of a proper catalyst and compliance with the annual tpy GHG emission limitation for the Thermal Oxidizer.

6.7.1.3 *Best Operating Practices*

Operating envelopes for the Glycol unit will be guided by sound principles to prevent potentially costly degradation of the catalyst. Because CO_2 emissions from the unit are ultimately based on the effectiveness of the catalyst, emissions will be minimized by keeping the unit in stable operation so that the catalyst effectiveness is not diminished.

6.7.2 Step 2 – Eliminate Technically Infeasible Options

All control technologies identified in Section 6.7.1 are considered technically feasible.

6.7.3 Step 3 – Rank Remaining Control Technologies

The CCS control option possibility is generally estimated at 90%, while good process design and best operational practices do not have the same quantitative consideration. CCS is therefore ranked as the highest potential control technology.

6.7.4 Step 4 – Evaluate the Most Effective Controls and Document Results

6.7.4.1 *CCS*

The cost discussion in Section 6.2.4.1 applies to a CCS control option for the byproduct vent because the same technological scenario of capturing stack gases then compressing and transporting CO_2 would be required for the byproduct vent as would be required for boiler/furnace flue gas stack; however, the cost-effectiveness of a CCS system has been evaluated taking into account the higher concentration of CO_2 in the vent which reduces the investment for purifying the stream. The capital cost of the CCS system for the byproduct vent is estimated to be over $244,000,000. The emissions of 301,135 tpy CO_2 from Table 6-6b yields a cost-effectiveness of 67.26 $/ton CO_2 for CCS vent control.

6.7.4.2 *Good Process Design*

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.7.4.3 *Best Operating Practices*

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.7.5 Step 5 – Selection of BACT

GCGV will select the appropriate catalyst and replace the catalyst to maintain effectiveness. Good process design and best operating practices are GHG BACT for the Byproduct Vent. BACT performance will be demonstrated through compliance with GHG annual mass rate (tpy) emission limits.

6.8 Glycol Thermal Oxidizer

The Glycol thermal oxidizer will be provided in the project for highly efficient destruction of noncondensible streams in the Glycol unit. The unit will be a source of GHG via similar mechanisms as are attributed to flares.

6.8.1 Step 1 – Identify CO_2e Control Technologies

The following potential GHG control strategies for the thermal oxidizer were considered as part of this BACT analysis:

- Good Combustor Design;
- Heat Recovery; and
- Best Operational Practices.

6.8.1.1 *Good Combustor Design*

The thermal oxidizer will be designed to combust VOC to its required destruction efficiency by ensuring adequate temperature, turbulence and time in the combustion chamber. Burners firing natural gas will provide any heat needed to supplement the heating value of the vent gas to bring the firebox to a temperature requirement that ensures oxidation of volatile compounds in the vent gas. Ducts and blowers will induce adequate movement of ambient air into the combustion chamber to provide oxygen for combustion. The vent gas flow through the chamber will be optimized with the dimensions of the chamber.

6.8.1.2 *Heat Recovery*

Heat recovery for the thermal oxidizer also includes using Glycol vent gas for fuel. Using the vent gas as the fuel for the thermal oxidizer reduces the amount of natural gas addition needed, and the heat produced by combusting the vent provides heat needed for control to the VOCs from the Byproduct vent.

6.8.1.3 *Best Operating Practices*

The primary operating requirement for the thermal oxidizer is temperature, which will be read in the combustion chamber with a durable monitor. Additionally, excess oxygen in the flue gas will be monitored to prevent combusting too much ambient air which would result in lowered thermal efficiency of the unit.

6.8.2 Step 2 – Eliminate Technically Infeasible Options

All control technologies identified in Section 6.8.1 are considered technically feasible.

6.8.3 Step 3 – Rank Remaining Control Technologies

Good combustor design and best operational practices are the most effective options for control.

6.8.4 Step 4 – Evaluate the Most Effective Controls and Document Results

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.8.5 Step 5 – Selection of BACT

GCGV will include up-to-date thermal oxidizer design with an appropriately sized combustion chamber and air handling systems. The temperature in the combustor chamber and oxygen in the flue gases will be continuously monitored to ensure good thermal efficiency of the unit. BACT performance will be demonstrated through compliance with the device's minimum temperature requirement reflecting good operation, and compliance with GHG annual mass rate (tpy) emission limits.

6.9 Regeneration Vents

The regeneration of reactor beds in the coproducts section of olefins, and regeneration of purification beds in the raw materials treatment section of polyethylene generates a small amount of emissions (less than 0.01% of total GHG emissions from the project).

6.9.1 Step 1 – Identify CO_2e Control Technologies

The following potential GHG control strategies for the byproduct vent were considered as part of this BACT analysis:

- Good Process Design;
- Best Operational Practices; and
- CCS.

6.9.1.1 *Good Process Design*

The proprietary design and reactor technology used in the conversion process minimizes carbon buildup in the catalyst, providing for maximum heat transfer in the catalyst and minimizing associated emissions.

6.9.1.2 *Best Operating Practices*

Regeneration events will be conducted according to standard operating procedures and limited in frequency to stay within annual GHG emissions limits.

6.9.1.3 *CCS*

Please refer to Section 6.2.2.1 for a discussion of CCS.

6.9.2 Step 2 – Eliminate Technically Infeasible Options

All control measures identified in Section 6.9.1 are considered technically feasible.

6.9.3 Step 3 – Rank Remaining Control Technologies

There are no negative economic, energy, or environmental impacts associated with the control measures identified in Section 6.9.1.

6.9.4 Step 4 – Evaluate the Most Effective Controls and Document Results

Because the emissions from this source are < 0.01 % of the emissions from either the project's boilers or furnaces, and CCS is not economically reasonable for the project's boiler and furnace flue gases, CCS is not economically reasonable for Regeneration Vents. Good Process Design and Best Operating Practices are selected as BACT for Olefins Regeneration Vent.

6.9.5 Step 5 – Selection of BACT

GCGV will select the appropriate catalyst and replace the catalyst to maintain effectiveness. Good process design and best operating practices are GHG BACT for the regeneration vents. BACT performance will be demonstrated through compliance with GHG annual mass rate (tpy) emission limits.

6.10 Shared Thermal Oxidizer

A shared thermal oxidizer disposition will be provided in the project for highly efficient destruction of vent gas streams in the olefins, utilities, and polyethylene units. Two identical units under EPN: UFF01 will be a source of GHG via similar mechanisms as are attributed to flares.

6.10.1 Step 1 – Identify CO_2e Control Technologies

The following potential GHG control strategies for the thermal oxidizer were considered as part of this BACT analysis:

- Good Combustor Design;
- Heat Recovery; and
- Best Operational Practices.

6.10.1.1 *Good Combustor Design*

The thermal oxidizer will be designed to combust VOC to a minimum destruction efficiency of 99% or 10 ppmv outlet VOC concentration by ensuring adequate temperature, turbulence and time in the combustion chamber. The Shared Thermal Oxidizer will control streams with a variety of heating values and flow rates. The minimum temperature will be maintained by low pressure vent gas with natural gas addition. Ducts and blowers will induce adequate movement of ambient air into the combustion chamber to provide oxygen for combustion. The vent gas flow through the chamber will be optimized with the dimensions of the chamber.

6.10.1.2 *Heat Recovery*

Process fluid or boiler feed water preheat is a method of recovering heat from the hot combustion flue gas produced by direct fired thermal oxidizers through heat exchange with the boiler feed water or a process fluid. Preheating of process fluids reduces the amount of fuel required by the process heater or steam generated by a boiler.

6.10.1.3 *Best Operating Practices*

The primary operating requirement for the thermal oxidizer is temperature, which will be read in the combustion chamber with a durable monitor. Additionally, excess oxygen in the flue gas will be monitored to prevent combusting too much ambient air which would result in lowered thermal efficiency of the unit.

6.10.2 Step 2 – Eliminate Technically Infeasible Options

Good combustor design and Best Operating Practices are considered technically feasible; however, for the thermal oxidizer design case a heat recovery design is not appropriate. Heat recovery is technically infeasible because the use of heat integration in the thermal oxidizer would reduce the effectiveness of heat integration in the furnaces and boilers and result is the facility being out of fuel gas balance which leads to flaring.

6.10.3 Step 3 – Rank Remaining Control Technologies

Good combustor design and best operational practices are the most effective options for control.

6.10.4 Step 4 – Evaluate the Most Effective Controls and Document Results

No energy or environmental impacts (that would influence the GHG BACT selection process) would eliminate any of the remaining control options.

6.10.5 Step 5 – Selection of BACT

GCGV will include up-to-date thermal oxidizer design with an appropriately sized combustion chamber and air handling systems. The temperature in the combustor chamber and oxygen in the flue gases will be continuously monitored to ensure good thermal efficiency of the unit. BACT performance will be demonstrated through compliance with the device's minimum temperature requirement reflecting good operation, and compliance with GHG annual mass rate (tpy) emission limits.

Table 6-5 GHG RBLC Query Results

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
TICONA POLYMERS, INC.	BISHOP FACILITY	TX	Carbon Dioxide Equivalent (CO2e)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer	Firing of pipeline quality natural gas and high hydrogen process gas. CO2eq (CH4, N2O, and CO2) emissions are controlled through heat integration and best management practices. : 533629 TPY
TICONA POLYMERS, INC.	BISHOP FACILITY	TX	Carbon Dioxide Equivalent (CO2e)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Fugitives	28VHP fugitive monitoring program on lines containing >10% methane : 344 TPY
TICONA POLYMERS, INC.	BISHOP FACILITY	TX	Carbon Dioxide Equivalent (CO2e)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Reformer Start up and Shutdown	flare 60.18 : 45678 TPY
TICONA POLYMERS, INC.	BISHOP FACILITY	TX	Carbon Dioxide Equivalent (CO2e)	11/12/2015	123216, PSDTX1438 AND GHGPSDTX	Cooling Tower	Minimize methane leaks into cooling water. : 420 TPY
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Dioxide Equivalent (CO2e)	9/5/2014	13060007	Startup Heater	good combustion practices : 871 TPY
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Dioxide Equivalent (CO2e)	9/5/2014	13060007	Ammonia Pressure Tanks	Flare; flare minimization : 479 TPY

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Dioxide Equivalent (CO2e)	9/5/2014	13060007	Emergency Generator	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 432 TPY
CRONUS CHEMICALS, LLC	CRONUS CHEMICALS, LLC	IL	Carbon Dioxide Equivalent (CO2e)	9/5/2014	13060007	Firewater Pump Engine	Tier IV standards for non-road engines at 40 CFR 1039.102, Table 7. : 72 TPY
CROSSTEX PROCESSING SERVICES, LLC	EUNICE GAS EXTRACTION PLANT	LA	Carbon Dioxide Equivalent (CO2e)	5/1/2013	PSD-LA-569(M-1)	Process Fugitives (16) (FUG 0001)	LDAR programs: NSPS KKK and LAC 33:III.2121 : 0
CROSSTEX PROCESSING SERVICES, LLC	EUNICE GAS EXTRACTION PLANT	LA	Carbon Dioxide Equivalent (CO2e)	5/1/2013	PSD-LA-569(M-1)	Boiler B-101-G (12-1) (EQT 0061)	Energy efficiency measures: improved combustion measures (e.g., combustion tuning, optimization using parametric testing, advanced digital instrumentation such as temperature sensors, oxygen monitors, CO monitors, and oxygen trim controls); use of an economizer; boiler insulation; and minimization of air infiltration. : 0
CROSSTEX PROCESSING SERVICES, LLC	EUNICE GAS EXTRACTION PLANT	LA	Carbon Dioxide Equivalent (CO2e)	5/1/2013	PSD-LA-569(M-1)	Smokeless Flare (14) (EQT 0028)	Good combustion practices : 0

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Table 6-5. GHG RBLC Query Results							
Company	**Facility**	**State**	**Pollutant**	**Permit Date**	**Permit No.**	**RBLC Unit**	**Control Technology**
CROSSTEX PROCESSING SERVICES, LLC	EUNICE GAS EXTRACTION PLANT	LA	Carbon Dioxide Equivalent (CO2e)	5/1/2013	PSD-LA-569(M-1)	Regenerative Thermal Oxidizer (RTO) (EQT 0062)	Good combustion practices : 0
CROSSTEX PROCESSING SERVICES, LLC	EUNICE GAS EXTRACTION PLANT	LA	Carbon Dioxide Equivalent (CO2e)	5/1/2013	PSD-LA-569(M-1)	Compressor Engines 1, 2, & 3 (EQT 0057, 0058, & 0059)	Compliance with NSPS JJJJ : 0
EQUISTAR CHEMICALS, LP	EQUISTAR CHEMICALS, LP LA PORTE COMPLEX	TX	Carbon Dioxide Equivalent (CO2e)	3/14/2013	PSD-TX-752-GHG	Cracking Furnaces	Selective Catalytic Reduction (SCR) system : 281766 T/R 12 MONTH ROLLING AVERAGE
EQUISTAR CHEMICALS, LP	EQUISTAR CHEMICALS, LP LA PORTE COMPLEX	TX	Carbon Dioxide Equivalent (CO2e)	3/14/2013	PSD-TX-752-GHG	Flares	: 39046 T/Y 12-MONTH ROLLING AVERAGE
EQUISTAR CHEMICALS, LP (EQUISTAR)	EQUISTAR CHEMICALS, LP - CHANNELVIEW NORTH PLANT	TX	Carbon Dioxide Equivalent (CO2e)	2/14/2013	PSD-TX-1280-GHG	Reformer Furnace (Combustion Unit).	Selective Catalytic Reduction (SCR) system and low NOx burners. : 826600 T/Y 365 ROLLING AVERAGE
EQUISTAR CHEMICALS, LP (EQUISTAR)	EQUISTAR CHEMICALS, LP - CHANNELVIEW NORTH PLANT	TX	Methane	2/14/2013	PSD-TX-1280-GHG	Reformer Furnace (Combustion Unit).	Selective Catalytic Reduction (SCR) system and low NOx burners. : 16 T/Y 365 ROLLING AVERAGE

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
EQUISTAR CHEMICALS, LP (EQUISTAR)	EQUISTAR CHEMICALS, LP - CHANNELVIEW NORTH PLANT	TX	Nitrous Oxide (N2O)	2/14/2013	PSD-TX-1280-GHG	Reformer Furnace (Combustion Unit).	: 2 T/Y 12-MONTH ROLLING AVERAGE
EQUISTAR CHEMICALS, LP (EQUISTAR)	EQUISTAR CHEMICALS, LP - CHANNELVIEW NORTH PLANT	TX	Carbon Dioxide Equivalent (CO2e)	2/14/2013	PSD-TX-1280-GHG	Methanol Flare and Methanol Emergency Flare (Combustion Unit)	: 3936 T/Y 12-MONTH ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Carbon Dioxide	1/17/2013	PSD-TX-748-GHG	Ethylene Cracking Furnace	: 206000 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Nitrous Oxide (N2O)	1/17/2013	PSD-TX-748-GHG	Ethylene Cracking Furnace	Chevron Phillips elects to reduce the overall emissions from the furnaces by utilizing a compliance cap for the furnaces and boiler of 1,579,000 tpy CO2e. Since steam generation from the furnaces is integrated with steam generation from the VHP boiler, the annual emissions from the boiler are included in the compliance cap. : 11.9 T/YR 365-DAY ROLLING AVERAGE

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Methane	1/17/2013	PSD-TX-748-GHG	Ethylene Cracking Furnace	: 11.9 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Carbon Dioxide	1/17/2013	PSD-TX-748-GHG	Very High Pressure (VHP) Boiler	: 127000 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Methane	1/17/2013	PSD-TX-748-GHG	Very High Pressure (VHP) Boiler	: 6.5 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Nitrous Oxide (N2O)	1/17/2013	PSD-TX-748-GHG	Very High Pressure (VHP) Boiler	: 1.1 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Carbon Dioxide	1/17/2013	PSD-TX-748-GHG	Vapor Destruction Unit	: 2400 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Methane	1/17/2013	PSD-TX-748-GHG	Vapor Destruction Unit	: 0.046 T/YR 365-DAY ROLLING AVERAGE

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Nitrous Oxide (N2O)	1/17/2013	PSD-TX-748-GHG	Vapor Destruction Unit	: 0.0046 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Carbon Dioxide	1/17/2013	PSD-TX-748-GHG	Emergency Generator Engines	: 274 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Methane	1/17/2013	PSD-TX-748-GHG	Emergency Generator Engines	: 0.011 T/YR 365-DAY ROLLING AVERAGE
CHEVRON PHILLIPS CHEMICAL COMPANY, LP	CEDAR BAYOU PLANT, UNIT 1594	TX	Nitrous Oxide (N2O)	1/17/2013	PSD-TX-748-GHG	Emergency Generator Engines	: 0.002 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide	10/12/2012	PSD-TX-93813-GHG	FRAC I and II Hot Oil Heaters	: 137943 T/YR 365-DAY TOTAL, ROLLED DAILY
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide Equivalent (CO2e)	10/12/2012	PSD-TX-93813-GHG	FRAC I and II Hot Oil Heaters	: 138078 T/YR 12-MONTH ROLLING BASIS

Table 6-5 GHG RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Nitrous Oxide (N2O)	10/12/2012	PSD-TX-93813-GHG	FRAC I and II Hot Oil Heaters	: 0.26 T/YR 365-DAY TOTAL, ROLLED DAILY
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Methane	10/12/2012	PSD-TX-93813-GHG	FRAC I and II Hot Oil Heaters	: 2.6 T/YR 365-DAY TOTAL, ROLLED DAILY
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide	10/12/2012	PSD-TX-93813-GHG	Molecular Sieve Regeneration Heater	: 23501 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide Equivalent (CO2e)	10/12/2012	PSD-TX-93813-GHG	Molecular Sieve Regeneration Heater	: 23501 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Methane	10/12/2012	PSD-TX-93813-GHG	Molecular Sieve Regeneration Heater	: 0.44 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Nitrous Oxide (N2O)	10/12/2012	PSD-TX-93813-GHG	Molecular Sieve Regeneration Heater	: 0.04 T/YR 365-DAY ROLLING AVERAGE

Table 6-5 GHG RBLC Query Results
(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide Equivalent (CO2e)	10/12/2012	PSD-TX-93813-GHG	Thermal Oxidizers	: 36406 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Carbon Dioxide	10/12/2012	PSD-TX-93813-GHG	Thermal Oxidizers	: 36406 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Methane	10/12/2012	PSD-TX-93813-GHG	Thermal Oxidizers	: 0.18 T/YR 365-DAY ROLLING AVERAGE
ENERGY TRANSFER PARTNERS, LP	LONE STAR NGL, MONT BELVIEU GAS PLANT	TX	Nitrous Oxide (N2O)	10/12/2012	PSD-TX-93813-GHG	Thermal Oxidizers	: 0.02 T/YR 365-DAY ROLLING AVERAGE
BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	Carbon Dioxide	8/24/2012	PSD-TX-903-GHG	Ethylene Cracking Furnace No. 10	Selective Catalytic Reduction system. : 255735 T/YR 12-MONTH ROLLING AVERAGE
BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	Carbon Dioxide	8/24/2012	PSD-TX-903-GHG	Stem Package Boilers	Selective Catalytic Reduction Controls (SCR) : 420095 T/YR 12-MONTH ROLLING AVG BASIS
BASF TOTAL PETROCHMICALS LP	BASF TOTAL PETROCHMICALS LP	TX	Carbon Dioxide	8/24/2012	PSD-TX- 903-GHG	Gas Turbine Auxiliar y Duct	Selective Catalytic Reduction Control (SCR). : 117786 T/YR 365-DAY ROLLING AVERAGE.

Table 6-5 GHG RBLC Query Results

(Continued from previous page)

Company	Facility	State	Pollutant	Permit Date	Permit No.	RBLC Unit	Control Technology
ENERGY TRASFER PARTNERS, LP (ETP)	LONE STAR NGL MONT BELVIEW GAS PLANT(LONE STAR)	TX	Carbon Dioxide	5/24/2012	PSD-TX-1264-GHG	Compressor Engine Groups	: 1871.7 LB/MMSCF CO2 365-DAY ROLLING AVG
ENERGY TRASFER PARTNERS, LP (ETP)	LONE STAR NGL MONT BELVIEW GAS PLANT(LONE STAR)	TX	Carbon Dioxide	5/24/2012	PSD-TX-1264-GHG	Plant Heater System	: 1102.5 LB/MMSCF CO2 365-DAY ROLLING AVG.

Table 6-6a: CCS Cost Calculations Furances

CO_2 Pipeline/Injection Well/Plant Assumptions	
Pipeline Length	170 miles
Pipeline Diameter	10 inches

Carbon Capturing System Cost Estimate			
Cost Type	**Units**	**Cost**	
Pipeline Costs [1]			
Pipeline Materials	\$ Diameter (inches),Length (miles)	$\$70,350 + \$2.01 \times L \times (330.5 \times D^2 + 687.7 \times D + 26,920)$	\$24,741,237
Pipeline Labor	\$ Diameter (inches),Length (miles)	$\$371,850 + \$2.01 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	\$83,461,638
Pipeline Miscellaneous	\$ Diameter (inches),Length (miles)	$\$147,250 + \$1.55 \times L \times (8,417 \times D + 7,234)$	\$26,170,780
Pipeline Right of Way	\$ Diameter (inches),Length (miles)	$\$51,200 + \$1.28 \times L \times (577 \times D + 29,788)$	\$8,411,710
Pipeline Booster Stations	\$	Engineering Estimate	\$60,000,000
Other Capital [2]			
CO_2 Amine Removal System	\$	Engineering Estimate	\$641,550,000
CO_2 Compression and Drying	\$	Engineering Estimate	\$128,310,000
Plant Impacts	\$	Engineering Estimate	\$174,370,000
Auxiliary Boiler	\$	Engineering Estimate	\$73,070,000
O&M - Pipeline [3]			
Fixed O&M	\$/mile/year	\$8,454	\$1,437,180
O&M - Capture			
Fixed O&M	% of installed capital	3.5%	\$10,822,000
CO_2 CCS Natural Gas Consumption	\$ per MMBtu	Engineering Estimate	\$36,300,000
Amine Replacement	\$ per year		
		Total CCS Capital Cost	**\$1,220,085,366**

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013.

2. National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," NETL - Rev. 2a, November 2013.

3. National Energy Technology Laboratory, "Estimating Carbon Dioxide Transport and Storage Costs," DOE/NETL-400/2010/1447, March 2010

Table 6-6a: CCS Cost Calculations Furances

Amortized CCS Cost	
CCS Total Capital Investment (TCI)	$1,220,085,366
Capital Recovery Factor (CRF) = $i(1+i)^n/((1+i)^n-1)$	0.0981
i = interest rate[2]	0.075
n = equipment life, years	20
Amortized Installation Costs = CRF x TCI	$119,680,847.48
Annual O&M Costs	$48,559,180
Total CCS Annualized Cost	$168,240,027.48
Tons CO_2 per Year Removed	2,009,098
CO_2 Sold for EOR ($/ton)[1]	$20.00
Average Annual Cost per Ton CO_2 Removed	**$63.74**
(Assuming 90% Capture and Transfer)	

1. From Sierra Club comments on Freeport LNG GHG application; $9 to $34 per ton CO2. The midpoint of this range was used.

2. Market Rate

Table B6-6b: CCS Cost Calculations Glycol Vent

CO_2 Pipeline/Injection Well/Plant Assumptions	
Pipeline Length	170 miles
Pipeline Diameter	4 inches

Carbon Capturing System Cost Estimate			
Cost Type	Units	Cost	
Pipeline Costs [1]			
Pipeline Materials	\$ Diameter (inches),Length (miles)	$\$70,350 + \$2.01 \times L \times (330.5 \times D^2 + 687.7 \times D + 26,920)$	\$12,975,558
Pipeline Labor	\$ Diameter (inches),Length (miles)	$\$371,850 + \$2.01 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$	\$68,230,489
Pipeline Miscellaneous	\$ Diameter (inches),Length (miles)	$\$147,250 + \$1.55 \times L \times (8,417 \times D + 7,234)$	\$11,798,921
Pipeline Right of Way	\$ Diameter (inches),Length (miles)	$\$51,200 + \$1.28 \times L \times (577 \times D + 29,788)$	\$7,598,113
Pipeline Booster Stations	\$	Engineering Estimate	\$60,000,000
CO_2 Compression and Drying	\$	Engineering Estimate	\$83,566,000
Fixed O&M Pipeline	\$/mile/year	\$8,454	\$1,437,180
Fixed O&M Compression and Drying	% of installed capital	3.5%	\$889,000
		Total CCS Capital Cost	**\$244,169,080**

1. National Energy Technology Laboratory, "Carbon Dioxide Transport and Storage Costs in NETL Studies," DOE/NETL - 2013/1614, March 2013.

2. National Energy Technology Laboratory, "Cost and Performance Baseline for Fossil Energy Plants," NETL - Rev. 2a, November 2013.

3. National Energy Technology Laboratory, "Estimating Carbon Dioxide Transport and Storage Costs," DOE/NETL-400/2010/1447, March 2010

Table B6-6b: CCS Cost Calculations Glycol Vent

Amortized CCS Cost	
CCS Total Capital Investment (TCI)	\$244,169,080
Capital Recovery Factor (CRF) = $i(1+i)^n/((1+i)^n-1)$	0.0981
i = interest rate[2]	0.075
n = equipment life, years	20
Amortized Installation Costs = CRF x TCI	\$23,951,080.20
Annual O&M Costs	\$2,326,180
Total CCS Annualized Cost	\$26,277,260.20
Tons CO_2 per Year Removed	301,135
CO_2 Sold for EOR (\$/ton)[1]	\$20.00
Average Annual Cost per Ton CO_2 Removed	**\$67.26**
(Assuming 90% Capture and Transfer)	

1. From Sierra Club comments on Freeport LNG GHG application; \$9 to \$34 per ton CO2. The midpoint of this range was used

2. Market Rate