12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203
trinityconsultants.com

Trinity Consultants

February 17, 2012

Mr. Jeff Robinson
Permit Section Chief
U.S. Environmental Protection Agency, (6PD-R)
1445 Ross Ave
Dallas, TX 75202-2733

RE: *Application for Prevention of Significant Deterioration for Greenhouse Gas Emissions*
Targa Gas Processing LLC – Longhorn Gas Plant
Wise County, Texas

Dear Mr. Robinson:

Targa Gas Processing LLC (Targa) is proposing to construct a natural gas processing plant near Decatur in Wise County, Texas (Longhorn Gas Plant). The primary Standard Industrial Classification code of the proposed Longhorn Gas Plant is 1321 (Natural Gas Liquids). The Longhorn Gas Plant will be designed to process up to 200 million standard cubic feet per day of sweet natural gas. The Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, a glycol dehydration unit, a cryogenic processing skid and supporting equipment.

The proposed Longhorn Gas Plant will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements under the GHG Tailoring Rule. With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action. Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. As shown in the enclosed permit application, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG pollutants. Therefore, all non-GHG pollutants are subject to the jurisdiction of the TCEQ for minor source state NSR permitting. Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The minor source state NSR permit application for non-GHG pollutants submitted to TCEQ is included as an appendix of this GHG PSD permit application for reference.

This permit application is prepared in accordance with EPA guidance. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology evaluation, emissions calculations, process description and flow diagram, and supporting documentation.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Ms. Melanie Roberts, Targa, at (713) 584-1422.

Sincerely,

TRINITY CONSULTANTS

Jessica Coleman

Jessica Coleman
Senior Consultant

Enclosure

cc: Mr. Clark White, VP & Region Manager, Targa
Ms. Jessica Keiser, Assistant VP ES&H, Targa
Ms. Melanie Roberts, Environmental Manager, Targa
Ms. Christine Chambers, Manager of Consulting Services - Dallas, Trinity Consultants

PREVENTION OF SIGNIFICANT DETERIORATION PERMIT APPLICATION FOR GREENHOUSE GASES

Targa Gas Processing LLC > Longhorn Gas Plant

Prepared By:

Jessica Keiser – Assistant VP ES&H
Melanie Roberts – Environmental Manager

TARGA GAS PROCESSING LLC
1000 Louisiana St.
Suite 4300
Houston, TX 77002
(713) 584-1422
Fax: (713) 584-1100

Christine Chambers – Managing Consultant
Jessica Coleman – Senior Consultant
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February 2012

Project 114401.0161

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Environmental solutions delivered uncommonly well

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Targa Gas Processing LLC (Targa) is proposing to construct a natural gas processing plant near Decatur in Wise County, Texas (Longhorn Gas Plant). The primary Standard Industrial Classification code of the proposed Longhorn Gas Plant is 1321 (Natural Gas Liquids). The proposed facility will be a minor source with respect to all criteria pollutants and hazardous air pollutants (HAP). The proposed facility will be a major source of greenhouse gas (GHG) emissions. Targa is submitting this Prevention of Significant Deterioration (PSD) permit application to authorize GHG emissions from the proposed Longhorn Gas Plant. The analyses related to the Endangered Species Act and National Historic Preservation Act will be addressed in separate filings.

1.1. PROPOSED PROJECT

The Longhorn Gas Plant will be designed to process up to 200 million standard cubic feet per day (MMscfd) of sweet natural gas. The Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, a glycol dehydration unit, a cryogenic processing skid and supporting equipment. The main processes at the Longhorn Gas Plant will include the following:

- Inlet separation facilities
- Removal of carbon dioxide (CO_2) from natural gas through amine treating
- Removal of water from natural gas through glycol dehydration and in molecular sieve dehydrator beds
- Separation of natural gas liquids from natural gas through a cryogenic process
- Compression of natural gas by electric-driven compressors
- Pipeline loading of high-pressure condensate liquids
- Truck loading of low-pressure condensate and produced water liquids

The proposed Longhorn Gas Plant will include the following emissions sources:

- Amine treater
- Tri-ethylene glycol (TEG) dehydrator
- Heaters
- Tanks
- Truck loading
- Regenerative thermal oxidizer (RTO)
- Process flare
- Planned maintenance, start-up, and shutdown (MSS) activities
- Equipment leak fugitives

A detailed process description is included in Section 6 of this permit application.

1.2. PERMITTING CONSIDERATIONS

1.2.1. Nonattainment Designations

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified for all criteria pollutants.[1] In a letter dated December 9, 2011, the United States

[1] Per 40 CFR §81.344 (Effective April 5, 2005).

Environmental Protection Agency (U.S. EPA) expressed its intent to designate Wise County as nonattainment for the eight-hour ozone standard and include it in the existing Dallas-Fort Worth (DFW) ozone nonattainment area.[2] In the event of a redesignation of Wise County to a serious nonattainment, the proposed Longhorn Gas Plant would be potentially subject to nonattainment new source review (NNSR) requirements for nitrogen dioxides (NO_x) and volatile organic compounds (VOC) if potential emissions exceed 50 tons per year (tpy) of either NO_x or VOC. Section 9 of this permit application includes an analysis demonstrating that the proposed Longhorn Gas Plant would not be considered a major source for ozone precursors under the proposed nonattainment designation, and will not be subject to NNSR permitting requirements even if Wise County is redesignated a serious ozone nonattainment area.

1.2.2. Greenhouse Gas Permitting Requirements

The proposed Longhorn Gas Plant will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements as EPA has interpreted them in the GHG Tailoring Rule.[3] In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources. Targa has determined that the GHG emissions from the proposed project will exceed 100,000 tpy as shown in Section 9 of this application. As a result, Targa has concluded that the proposed Longhorn Gas Plant will be a new major source with respect to GHGs.

With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[4] Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs.

As shown in Section 9 of this permit application, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG pollutants. Therefore, all non-GHG emissions are subject to the jurisdiction of the TCEQ for minor source state NSR permitting.

Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The minor source state NSR permit application submitted to TCEQ is included in Appendix G of this GHG PSD permit application for reference.

1.3. PERMIT APPLICATION

This permit application was prepared in accordance with EPA guidance. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology (BACT) evaluation, emissions calculations, process description and flow diagram, and other supporting documentation.

[2] Letter from Dr. Al Armendariz, U.S. EPA Region 6 Administrator, to Texas Governor Rick Perry, dated December 9, 2011.

[3] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[4] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

Texas Commission on Environmental Quality
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Air Preconstruction Permit and Amendment

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

I. Applicant Information		
A. Company or Other Legal Name: Targa Gas Processing LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Clark White		
Title: VP & Region Manager		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1525	Fax No.:	E-mail Address:
C. Technical Contact Name: Melanie Roberts		
Title: Environmental Manager		
Company Name: Targa Gas Processing LLC		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1422	Fax No.: 713-584-1522	E-mail Address: mroberts@targaresources.com
D. Site Name: Longhorn Gas Plant		
E. Area Name/Type of Facility: Natural Gas Processing Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Processing		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS):		
G. Projected Start of Construction Date: 11/01/2012		
Projected Start of Operation Date: 06/01/2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
NE on FM51 from US-380, turn left after 5.4 miles. Drive 1.25 miles to plant.		
City/Town: Decatur	County: Wise	ZIP Code: 76234
Latitude (nearest second): 33.310930	Longitude (nearest second): -97.526777	

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I. Applicant Information (continued)	
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 or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 86	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Craig Estes	District No.: 30
Representative: Phil King	District No.: 61
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☒ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III. Type of Permit Action Requested (continued)		
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐	
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐	
IV. Public Notice Applicability		
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers of an affected state?	☐ YES ☒ NO
If *Yes*, list the affected state(s).		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F.	List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*): **Please see Emission Data Section in Report**	
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NO_x):		
Particulate Matter (PM):		
PM $_{10}$ microns or less (PM_{10}):		
PM $_{2.5}$ microns or less ($PM_{2.5}$):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above:		

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V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Shane Tribe			
Title: Environmental Specialist			
Mailing Address: 383 CR 1745			
City: Chico	State: TX	ZIP Code: 76431	
B. Name of the Public Place: Decatur Public Library			
Physical Address (No P.O. Boxes): 1700 S FM 51			
City: Decatur	County: Wise	ZIP Code: 76234	
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
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable: Bill McElhaney			
Mailing Address: P.O. Box 393			
City: Decatur	State: TX	ZIP Code: 76234	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.			
Chief Executive: Joe A. Lambert			
Mailing Address: P.O. Box 1299			
City: Decatur	State: TX	ZIP Code: 76234	
Name of the Federal Land Manager:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	

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

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VII. Technical Information				
B. Are any schools located within 3,000 feet of this facility?				☐ YES ☒ NO
C. Maximum Operating Schedule:				
Hours: 24 hr/day	Day(s): 7 day/wk	Week(s): 52 wk/yr	Year(s): 8,760 hr/yr	
Seasonal Operation? If Yes, please describe in the space provide below.				☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?				☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.				
E. Does this application involve any air contaminants for which a *disaster review* is required?				☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?				☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*				
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?				☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?				☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?				☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?				☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*				
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?				☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?				☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?				☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***		
D.	Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E.	Do prevention of significant deterioration permitting requirements apply to this application?	☐ YES ☒ NO
F.	Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G.	Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal		
Is the estimated capital cost of the project greater than $2 million dollars?		☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.		
XI. Permit Fee Information		
Check, Money Order, Transaction Number ,ePay Voucher Number: 549317		Fee Amount: $75,000
Company name on check: Targa Resources Partners LP		Paid online?: ☐ YES ☒ NO
Is a copy of the check or money order attached to the original submittal of this application?		☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?		☒ YES ☐ NO ☐ N/A

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XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Clark White
Signature: Clark White *Original Signature Required*
Date: 2/16/2012

TCEQ Use Only

TCEQ Core Data Form

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)*

☒ 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. Attachments Describe Any Attachments: *(ex. Title V Application, Waste Transporter Application, etc.)*

☒Yes ☐No — Air New Source Review Permit Application

3. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	4. Regulated Entity Reference Number *(if issued)*
CN		RN

SECTION II: Customer Information

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

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

☐Owner ☐ Operator ☒ Owner & Operator
☐Occupational Licensee ☐ Responsible Party ☐ Voluntary Cleanup Applicant ☐Other: ____________

7. General Customer Information

☒ New Customer ☐ Update to Customer Information ☐ Change in Regulated Entity Ownership
☐Change in Legal Name (Verifiable with the Texas Secretary of State) ☐ No Change**

***If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.*

8. Type of Customer:	☒ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other: ____________

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)*	*If new Customer, enter previous Customer below*	*End Date:*
Targa Gas Processing LLC		

10. Mailing Address: 1000 Louisiana Street, Suite 4300

City	Houston	State	TX	ZIP	77002	ZIP + 4	

11. Country Mailing Information *(if outside USA)*	12. E-Mail Address *(if applicable)*

13. Telephone Number	14. Extension or Code	15. Fax Number *(if applicable)*
(713) 584-1000		( ) -

16. Federal Tax ID *(9 digits)*	17. TX State Franchise Tax ID *(11 digits)*	18. DUNS Number *(if applicable)*	19. TX SOS Filing Number *(if applicable)*
760507891	17605078918		

20. Number of Employees

☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☒ 501 and higher

21. Independently Owned and Operated? ☒ Yes ☐ No

SECTION III: Regulated Entity Information

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

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information ☐ No Change** *(See below)*

**If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.

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

Longhorn Gas Plant

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*							
	City		State		ZIP		ZIP + 4
25. Mailing Address:	383 County Road 1745						
	City	Chico	State	TX	ZIP	76431	ZIP + 4

26. E-Mail Address:	mroberts@targaresources.com

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(940) 644-2233		( ) -

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
1321			

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*
Natural Gas Processing

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	NE on FM51 from US-380, turn left after 5.4 miles. Drive 1.25 miles to plant.

36. Nearest City	County	State	Nearest ZIP Code
Decatur	Wise	TX	76234

37. Latitude (N) In Decimal:	33.310930°		38. Longitude (W) In Decimal:	-97.526777°	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds

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 or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

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

SECTION IV: Preparer Information

40. Name:	Melanie Roberts	**41. Title:**	Environmental Manager
42. Telephone Number	**43. Ext./Code**	**44. Fax Number**	**45. E-Mail Address**
(713) 584-1422		(713) 584-1522	mroberts@targaresources.com

SECTION V: Authorized Signature

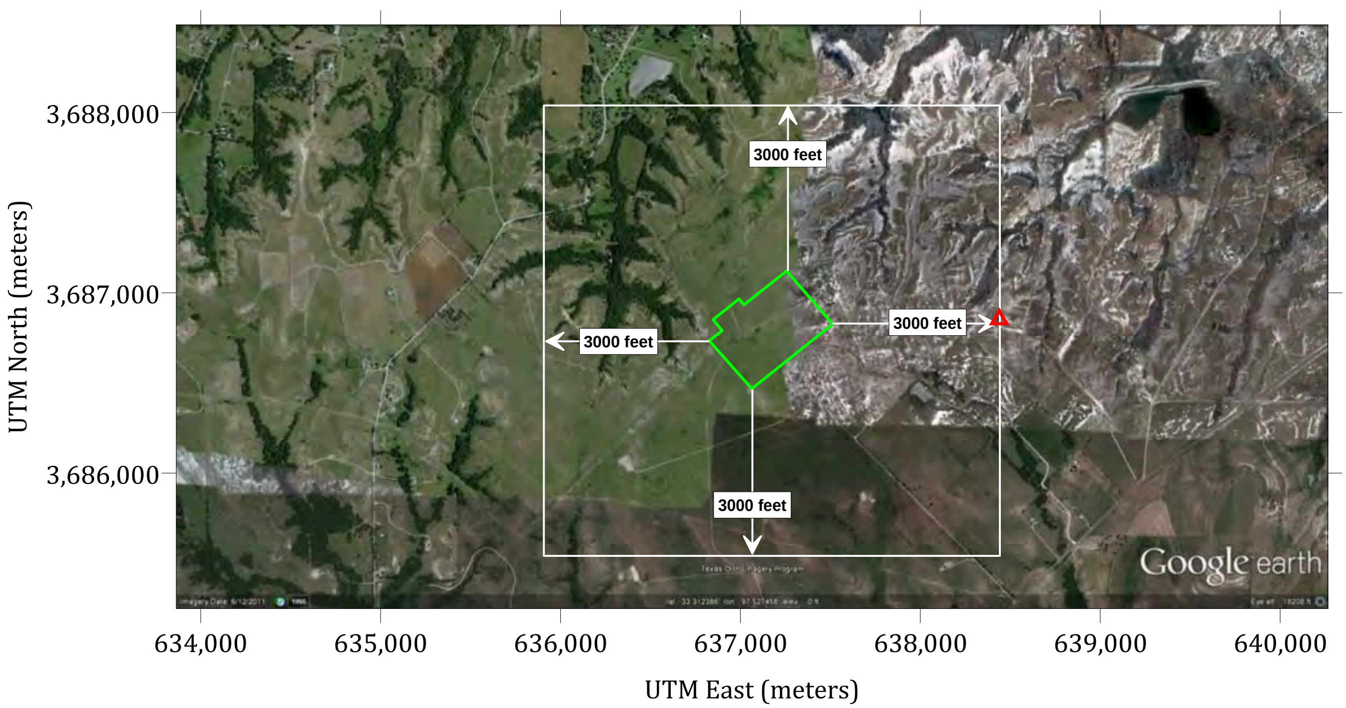
46. By my signature below, I certify, to the best of my knowledge, that the information provided in this form is true and complete, and that I have signature authority to submit this form on behalf of the entity specified in Section II, Field 9 and/or as required for the updates to the ID numbers identified in field 39.

(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Targa Gas Processing LLC	**Job Title:**	VP & Region Manager
Name *(In Print)*:	Clark White	**Phone:**	(713) 584-1525
Signature:	Clark White	**Date:**	2/16/2012

The Longhorn Gas Plant is located in Wise County, Texas. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 4-1 is an area map centered on the Longhorn Gas Plant that extends out at least 3,000 feet from the property line in all directions. The map depicts the fenceline/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). There are no schools within 3,000 feet of the facility boundary.

Figure 4-1
Targa Gas Processing LLC
Longhorn Plant Area Map

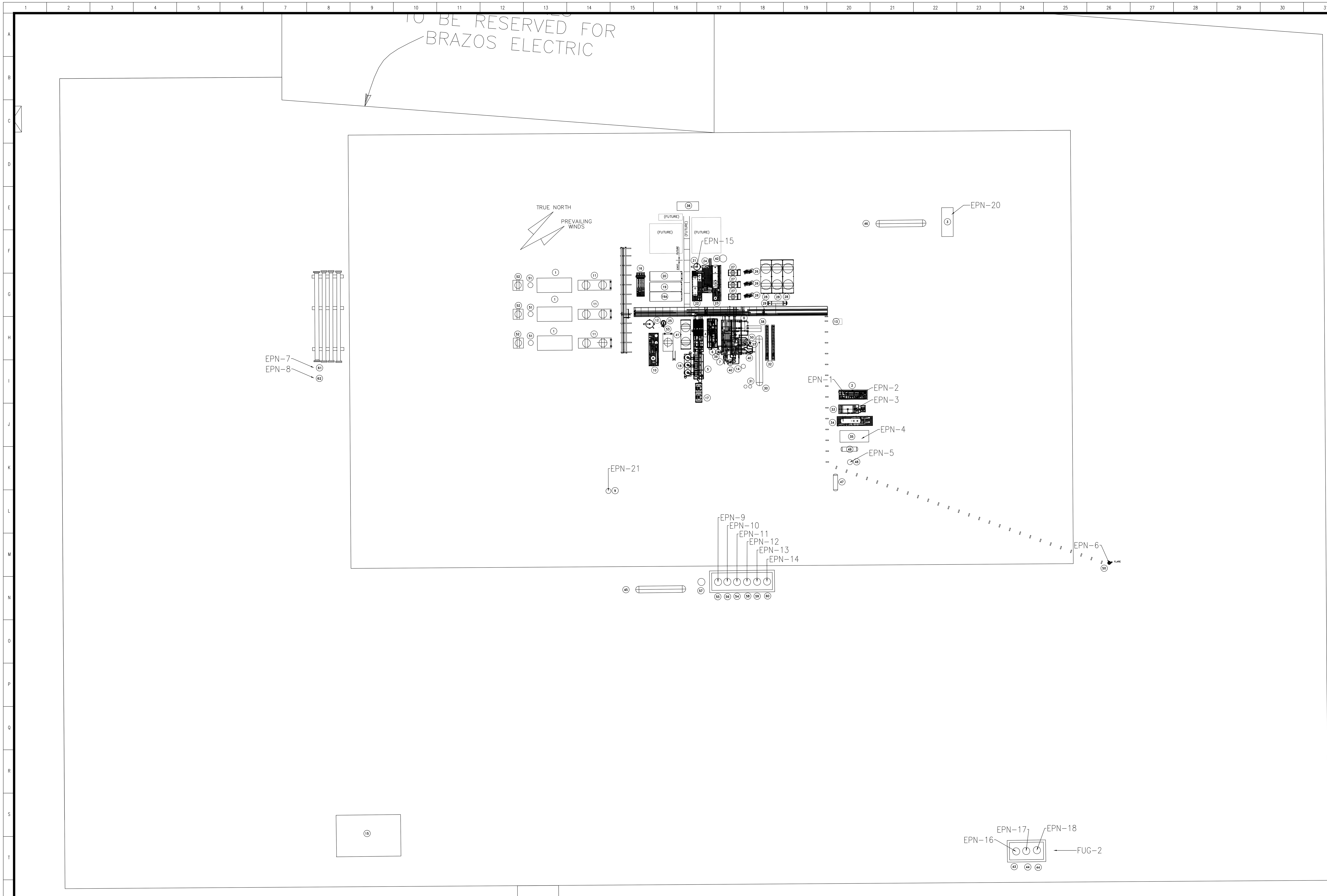


Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

Legend
Property Line
Residential Area

5. PLOT PLAN

The following figure depicts the site plans for the proposed Longhorn Gas Plant.



EQUIPMENT

1. RESIDUE COMPRESSOR
2. TEG REGEN SKID
3. REFRIGERANT UNLOADING
4. DEHY REGEN SKID #1
5. DEHY REGEN SKID #2
6. INLET GAS CHILLER SKID
7. PROCESS SKID #1
8. PROCESS SKID #2
9. OPEN DRAIN SUMP
10. INLET GAS SKID
11. RESIDUE COMPRESSOR COOLER
12. AMINE CONTACTOR
13. INSTRUMENT AIR COMPRESSOR
14. METHANOL STORAGE TANK
15. OFFICE/SHOP/WAREHOUSE/CONTROL ROOM
16. AMINE CIRCULATION PUMP SKID
17. REGEN GAS COOLER
18. MOL SIEVE DEHY ABSORBERS
19. AMINE COOLER (3 BAYS)
20. AMINE STILL REFLUX CONDENSER
21. AMINE STILL
22. REFLUX/BOOSTER SKID
23. AMINE FILTER SKID
24. AMINE REBOILER SKID
25. GLYCOL CONTACTOR
26. REFRIG COMPRESSORS
27. LUBE OIL COOLERS
28. REFRIG CONDENSER
29. REFRIG ACCUMULATOR
30. PRODUCT SURGE TANK
31. PRODUCT BOOSTER PUMP
32. PRODUCT PIPELINE PUMP
33. REGEN GAS HEATER
34. HEAT MED PUMP SKID
35. HEAT MED HEATER
36. MCC BUILDING
37. DEMETHANIZER TOWER
38. EXPANDER/COMPRESSOR
39. COLD SEPARATOR
40. BRAZED ALUMINUM EXCHANGERS
41. BOOSTER COMPRESSOR COOLER
42. AMINE DRAIN SUMP
43. WASTEWATER TANK
44. LOW PRESSURE CONDENSATE 2-210BBLS
45. CLOSED DRAIN TANK
46. REFRIGERANT PROPANE STORAGE
47. FLARE KO DRUM
48. THERMAL OXIDIZER KNOCK OUT DRUM
49. THERMAL OXIDIZER TANK
50. FLARE STACK
51. EXHAUST SILENCER
52. AUXILIARY COOLER 14'X14'
53. TREATED FIN FAN GAS COOLER 14'X25'
54. METHANOL 1000 GALLON TANK
55. TEG 210 BBL
56. HOT OIL STORAGE 210 BBL
57. DEIONIZED WATER 210 BBL
58. AMINE STORAGE 210 BBL
59. LUBE OIL 100 BBL 3612'S
60. LUBE OIL 100 BBL SCREW
61. 16" RECEIVER
62. 12" RECEIVER

EPN-1 TEG-1 GLYCOL HEATER
EPN-2 TEG-1 STILL VENT
EPN-3 HTR-1 REGEN HEATER
EPN-4 HTR-2 HEAT MED. HEATER
EPN-5 RTO-1 REGEN THERMAL OXIDIZER
EPN-6 FLARE-1 FLARE
EPN-7 PR-1 16" RECEIVER
EPN-8 PR-2 12" RECEIVER
EPN-9 TEG TANK TEG STORAGE 210 BBL
EPN-10 HOT OIL TANK HOT OIL STORAGE 210 BBL
EPN-11 MEOH-1 METHANOL STORAGE
EPN-12 AMINE TANK AMINE STORAGE 210 BBL
EPN-13 LUBE OIL TANK-1 3612 OIL 100 BBL
EPN-14 LUBE OIL TANK-2 REF OIL 100 BBL
EPN-15 AMINE STILL VENT-1 AMINE STILL VENT
EPN-16 WASTEWATER TANK 210 BBL
EPN-17 LOW PRESSURE CONDENSATE TANK-1 210 BBL
EPN-18 LOW PRESSURE CONDENSATE TANK-2 210 BBL
FUG-2 LOW PRESSURE CONDENSATE/WASTEWATER LOADING
EPN-20 REFRIGERANT UNLOADING
EPN-21 OPEN DRAIN SUMP

REFERENCE DWGS.	REV	DESCRIPTION	DWN	CHKD	DATE	REV	DESCRIPTION	DWN	CHKD	DATE
						C	REVISED PER FIELD MARK-UPS	TRA	JEO	2/16/12
						B	MOVED TANKS	TRA	JEO	12/22/11
						A	USED PLOT PLAN AS BASE TO CREATE THIS DRAWING	TRA	JEO	12/14/11

SCALE: 1" = 60'	DATE
DWN BY: TRA	12/14/11
CHKD BY: JEO	
FINAL CK:	
ENGR.:	
APPRV:	
APPRV:	

PREPARED BY: TARGA MIDSTREAM SERVICES LLC

PROJECT NUMBER:

PLANT NAME
LONGHORN
WISE COUNTY, TX

TARGA

PLOT PLAN
EMISSION POINTS

DRAWING NUMBER
116-100-E1

CAD FILE NAME
LH100E1

REVISION
0

PLOT DATE: 2/16/12

(TRA 2/16/12)

6. PROCESS DESCRIPTION & PROCESS FLOW DIAGRAM

The 200 MMscfd Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, glycol unit, cryogenic processing skid and supporting equipment. The supporting or auxiliary equipment consists of a hot oil heater, refrigeration system, regeneration heater, residue compression, regenerative thermal oxidizer, flare, and storage and truck loading and unloading facilities for consumable chemicals. A process flow diagram is included at the end of this section.

6.1. INLET AND SEPARATION

Gas will flow into the plant from either of two delivery points through high pressure pipelines equipped with onsite pipeline pig receivers (EPN 7-MSS, EPN 8-MSS). Gas from the pig receivers flows into the inlet slug catcher for liquid removal. The gas is then measured and goes through the Plant Inlet Separator for removal of any additional water, solids or liquids. Gas then flows to the Plant Inlet Filter/Separator for filtering of smaller particles of water and solids. Condensate from all inlet separation equipment is pumped back into a pipeline for delivery and handling at an existing facility located offsite.

6.2. GAS TREATING

After inlet separation and filtration, the inlet gas flows into the Amine Contactor, where the gas is contacted with an aqueous solution of UCARSOL AP-814 amine to remove CO_2. CO_2 exits with the amine from the bottom of the contactor and is heated and regenerated using closed hot oil system in the Amine Regenerator. Hot oil is circulated and supplied by the Heating Medium Heater (EPN 4). The CO_2 released from the regeneration process is routed to the onsite Regenerative Thermal Oxidizer, (RTO, EPN 5), where the vent gas is combusted and burned. When the RTO is down for maintenance the vent gas is routed to an atmospheric vent stack (EPN 15). Treated gas (less CO_2) exits the Amine Contactor and is routed to the Treated Gas Coolers where it is cooled with ambient air. Any condensed water drops out in the Treated Gas Scrubber. Water that does not drop out is recycled back to the amine process for reuse.

6.3. GAS DEHYDRATOR

Gas from the Treated Gas Scrubber then goes to the TEG Contactor where water removal is accomplished by contacting with Triethylene Glycol (TEG). The TEG is then regenerated in a 2.0 MMBtu/hr direct fired reboiler (EPN 1). Flash vapors from this unit go through an exchanger to remove condensables and then are routed back to the reboiler burner as fuel. Water removed from the TEG in the reboiler is cooled and any residual vapors are routed to the RTO (EPN 5) for combustion. During RTO maintenance the residual vapors are vented to the atmosphere (EPN 2). Dehydrated gas leaves the contactor and is exchanged with incoming glycol in a side mounted exchanger and then routed to the Mole Sieve Inlet Separator to recover any glycol carryover. Any recovered glycol/water is recycled back to the TEG system for reuse.

Gas exits the Mole Sieve Inlet Separator and flows into the Inlet Filter / Separator where it is again filtered prior to entering the Mole Sieve Dehydrator Beds. The gas flows into two (2) of the three (3) Mole Sieve Dehydrators for removal of any traces of water prior to the cryogenic process. Each dehydrator contains molecular sieve dehydration beads that absorb trace amounts of water from the gas stream. Two vessels will be used to dehydrate inlet gas while the third vessel is being regenerated. Dehydrated high pressure gas is used for regeneration. The regeneration gas is compressed by a Sundyne Compressor. The compressed gas flows to the Regeneration Gas Heater (EPN 3). The heater duty is not a 24 hour, continuous duty operation but only needed a few hours per day per bed. The hot gas flows from the heater to the dehydrator vessel being regenerated. The water is removed from the molecular sieve by evaporation. The hot gas and vaporized water flow to the Regeneration Gas Cooler, where the gas is cooled and the water is condensed. The cool regeneration gas stream flows to the Regeneration Gas Scrubber where condensed water is level controlled to the closed drain system flash tank and then to the plant waste water tank. The cooled gas recycles to the inlet of the plant upstream of the Inlet Filter/Separator. Dehydrated gas from the mole sieve beds flows into the Mole Sieve Dust Filters to remove any mole sieve particles prior to entry into the cryogenic process.

6.4. CRYOGENIC PROCESS

Gas flow into the Cryogenic Process is split to (2) plate fin type exchangers, Normally 60% will go to the Inlet Gas Exchanger, while the remainder flows to the Gas/Product Exchanger, then the Demethanizer reboiler, and then to the Demethanizer Side Reboiler or Heater. The Exchangers are combined into one plate fin exchanger. Gas vapor and liquid from the exchangers are combined and enter the Demethanizer Tower. The inlet gas is further cooled by heat exchange with propane refrigerant in the Inlet Gas Chiller. There are (3) 1500HP electric driven screw compressors that supply the process with refrigerant propane for cooling of the gas. Any heavier components collected in the refrigeration compressor scrubbers or system goes to the closed drain system flash tank. Refrigerant propane is loaded by truck into the Refrigerant Accumulator. Vapor and liquids from the chiller then flow to the Cold Separator. The Cold Separator is used to separate vapor and liquid hydrocarbons that have condensed as a result of chilling in the exchangers. Most of the vapor exiting the Cold Separator flows into the Expander side of the Expander/Booster Compressor where the temperature and pressure are reduced and enter the Demethanizer Tower. A portion of the Cold Separator liquids combines with a portion of the Cold Separator overhead vapors and flows to the Demethanizer Feed Subcooler where it is cooled with cold residue gas. The pressure is reduced and the stream feeds the top of the Demethanizer Tower. The remainder of the Cold Separator Liquid is level controlled to reduce the pressure and enters the Demethanizer Tower.

The Demethanizer Tower is a packed tower with a bottoms reboiler and a side reboiler (also known as a side heater). Liquids leaving the bottom of the tower flow to the Product Surge Tank. The product is then pumped by the Product Booster Pumps which are tandem seal centrifugal pumps, through the Gas/Product Exchanger where the product is heated by exchange with the inlet gas and then to the Product Pipeline Pumps which are tandem seal multistage centrifugal pumps. Overhead gas vapors (residue) from the Demethanizer Tower flows to the Demethanizer Feed Subcooler, then to the Inlet Gas Exchanger where the temperature is increased by heat exchange with the inlet gas. The residue leaving this exchanger is compressed by the Booster Compressor side of the Expander/Booster Compressor. Boosted residue is cooled in the Booster Compressor After-cooler and then flows to the residue compressors. Residue compressors comprise (3)-5,000 hp electric motor-driven reciprocating compressors which take the residue gas from plant residue pressure to pipeline sales pressure. Any compressor liquids accumulated from scrubbers is routed to the closed drain system flash tank. After cooling with fin fan units the residue gas is delivered by pipeline to the sales point offsite.

6.5. CLOSED DRAIN SYSTEM

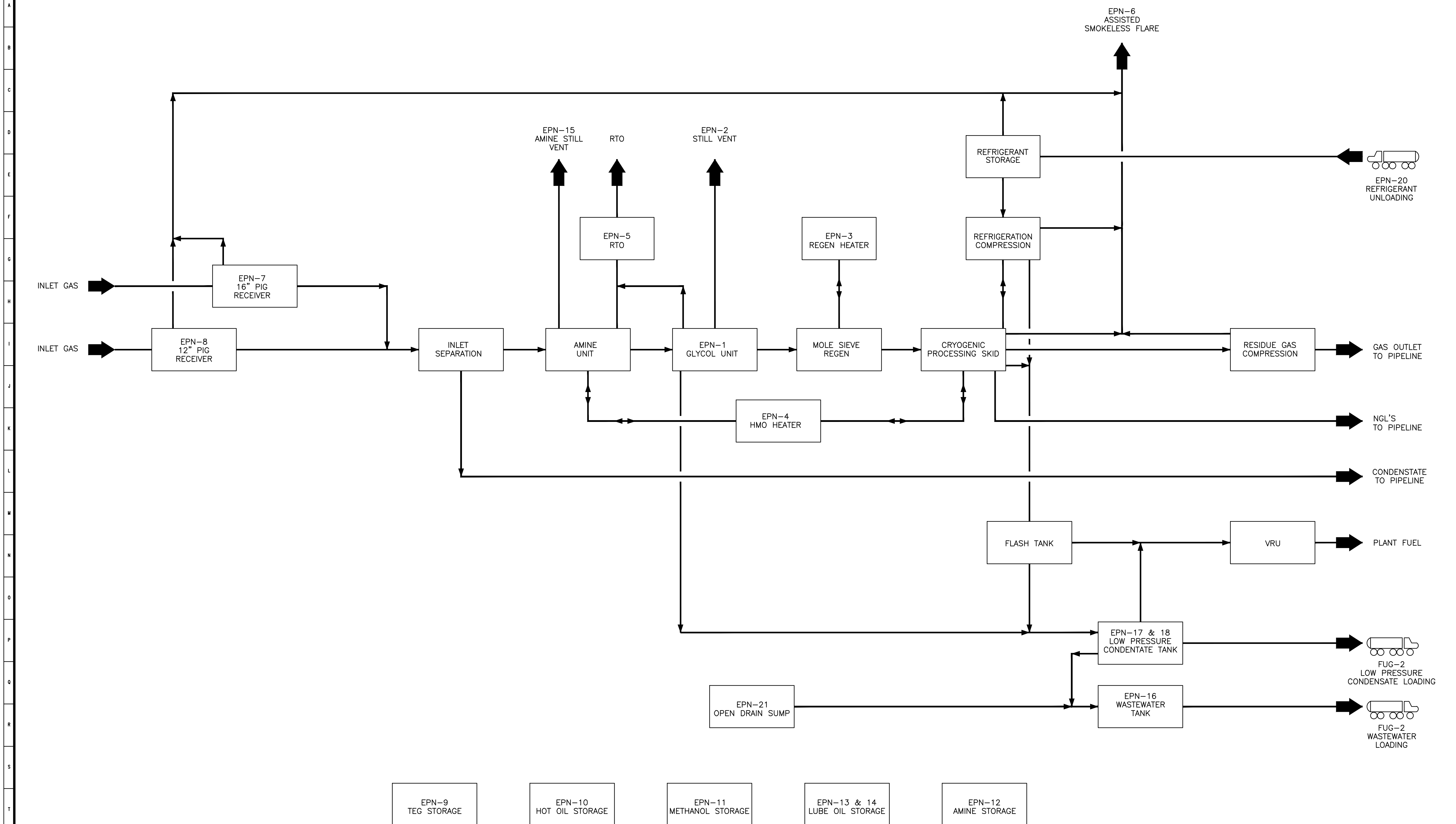
The closed drain system is designed with a flash tank that allows flash vapors to go to the plant fuel system via pressure feed or a vapor recovery unit. Liquids from the flash tank go to the low pressure condensate tanks (EPNs 17, 18). Water is separated out from the condensate and is drained to the waste water tank (EPN 16). Condensate is loaded out via trucks (FUG-2). Flash, working, and breathing vapors from the low pressure condensate tanks are controlled by the vapor recovery unit (VRU) and delivered to the plant fuel system.

6.6. OPEN DRAIN SYSTEM

The facility is equipped with an open (atmospheric) drain system to collect rain water and skid drain liquids to the open drain sump (EPN 21). The water collected in the sump flows to the waste water tank (EPN 16). Water in the waste water tank is loaded onto trucks for offsite handling.

6.7. FLARE SYSTEM

A 40 CFR §60.18 compliant flare (EPN 6) will be located on the facility site. This flare is air assisted, designed for smokeless operation. All pressure safety valves (PSV) containing heavier than air hydrocarbons, refrigeration system PSV's and compressor blowdowns and residue compressor blowdown vapors are routed to the flare.



REFERENCE DWGS.	REV	DESCRIPTION	DWN	CHKD	DATE	REV	DESCRIPTION	DWN	CHKD	DATE
						1	UPDATED PER FIELD	TRA	JEO	2/16/12
						0	UPDATED PER FIELD MARKUPS	TRA		2/10/12
						A	ISSUED FOR REVIEW	TRA		1/25/12

SCALE: NONE	DATE
DWN BY: TRA	1/25/12
CHKD BY: JEO	1/25/12
FINAL CK:	
ENGR.:	
APPRV:	
APPRV:	

PREPARED BY: TARGA TECHNICAL SERVICES

PROJECT NUMBER:

PLANT NAME
LONGHORN
WISE COUNTY, TX

TARGA

LONGHORN GAS PLANT
BLOCK FLOW DIAGRAM

DRAWING NUMBER 116-101-E
CAD FILE NAME LH101E
REVISION 1

PLOT DATE: 2/16/12

(TRA 2/16/12)

This section summarizes the GHG emission calculation methodologies and provides emission calculations for the emission sources at the proposed new Longhorn Gas Plant. Detailed emission calculation spreadsheets, including example calculations, are included at the end of this section. These emission estimates reflect the emission limits chosen as BACT in Section 10.

The following emission units are included in the GHG emission calculations provided at the end of this section:

- Three natural gas heaters (EPN 1, 3, 4);
- One amine treating unit (EPN 15);
- One TEG dehydrator (EPN 2);
- One RTO (EPN 5);
- Start-up activities from the RTO (EPN-5-MSS);
- One flare (EPN 6, 6-MSS);
- Fugitive emissions from piping components (EPN FUG-1); and
- Fugitive emissions from maintenance, start-up and shutdown activities (EPNs 7-MSS, 8-MSS, EPN FUG-MSS).

The operation of these sources will result in emissions of carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O).

Targa is also proposing to construct nine storage tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18) and to conduct truck loading operations (EPN FUG-2). However, based on the contents of the tanks, GHG emissions have been determined to be negligible and emission estimates for these operations are not included in this GHG PSD permit application.

According to Title 40 of the Code of Federal Regulations (40 CFR) Section (§)52.21(b)(49)(ii), PSD applicability for GHG emissions are determined based on GHG emissions on a carbon dioxide equivalent basis (CO_2e), as calculated by multiplying the mass of each of the six GHGs by the gas's associated global warming potential (GWP).[5] The GWP for each GHG proposed to be emitted at the Longhorn Gas Plant is listed in the following table.

Table 7-1. Greenhouse Gas Global Warming Potentials

CO_2	CH_4	N_2O
1	21	310

The following is an example calculation for hourly and annual CO_2e emissions:

$$\mathrm{CO_2e\ Hourly\ Emission\ Rate}\left(\frac{\mathrm{lb}}{\mathrm{hr}}\right) = \mathrm{CO_2\ Hourly\ Emission\ Rate}\left(\frac{\mathrm{lb}}{\mathrm{hr}}\right) \times \mathrm{CO_2\ GWP} + \mathrm{CH_4\ Hourly\ Emission\ Rate}\left(\frac{\mathrm{lb}}{\mathrm{hr}}\right) \times \mathrm{CH_4\ GWP} + \mathrm{N_2O\ Hourly\ Emission\ Rate}\left(\frac{\mathrm{lb}}{\mathrm{hr}}\right) \times \mathrm{N_2O\ GWP}$$

[5] 40 CFR Part 98, Subpart A, Table A-1.

$$CO_2e \text{ Annual Emission Rate (tpy)} = CO_2 \text{ Annual Emission Rate (tpy)} \times CO_2 \text{ GWP} + CH_4 \text{ Annual Emission Rate (tpy)} \times CH_4 \text{ GWP} + N_2O \text{ Annual Emission Rate (tpy)} \times N_2O \text{ GWP}$$

7.1. HEATERS

The Longhorn Gas Plant will include three natural gas-fired heaters: TEG Reboiler (EPN 1), Regeneration Heater (EPN 3), and Hot Oil Heater (EPN 4). Combustion of natural gas will result in GHG emissions of CO_2, CH_4, and N_2O.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule and as shown in the following table. [6]

Table 7.1-1. Natural Gas Combustion GHG Emission Factors

Units	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
lb/MMBtu *	116.89	2.20E-03	2.2E-04

*Emission factors are converted from kilograms to pounds using the conversion factor 2.2046 lb/kg.

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the heaters. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual CO_2, CH_4, and N_2O emission rates from the heaters:

$$\text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating} \left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor} \left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation} \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

7.2. AMINE TREATER

The Longhorn Gas Plant will include one amine treater (FIN 15). Emissions during normal operations from the amine still vent will be routed to the RTO (EPN 5), which has a destruction rate efficiency (DRE) of 99%. During RTO downtime, the amine emissions will be emitted directly to the atmosphere through the amine still vent (EPN 15). Emissions that occur during this alternate operating scenario are detailed in this section. Uncontrolled amine treater emissions will include CO_2 and CH_4. A discussion of emissions that occur during normal operations when the amine still vent is routed to the RTO is located in Section 7.4.

Hourly Emissions

Uncontrolled hourly CO_2 and CH_4 emissions from the amine treater that occur during RTO downtime are calculated using the ProMax® output for the waste stream. The following equation is used to estimate hourly CO_2 and CH_4 emission rates from the amine treater:

[6] 40 CFR Subpart C, Tables C-1 and C-2.

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{ProMax Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

The ProMax® simulation output file for the amine treater is provided in Appendix A for reference.

Annual Emissions

Annual emission rates for uncontrolled CO_2 and CH_4 during RTO downtime are estimated based on the hourly emission rate and expected RTO downtime frequency and duration, as shown in the following equation:

$$\text{Uncontrolled Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Number of events per Year}\left(\frac{\text{events}}{\text{yr}}\right) \times \text{Duration of event}\left(\frac{\text{hr}}{\text{events}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.3. GLYCOL DEHYDRATOR

The Longhorn Gas Plant will include one TEG dehydrator (FIN 2), which has a condenser to aid in the control of emissions. Emissions during normal operations from the condenser stream will be routed to the RTO (EPN 5), which has a DRE of 99%. During RTO downtime the condenser stream emissions will be emitted directly to the atmosphere through the dehydrator vent (EPN 2). Emissions that occur during this alternate operating scenario are detailed in this section. Uncontrolled TEG dehydrator GHG emissions will include CO_2 and CH_4. A discussion of emissions that occur during normal operations when the condenser stream is routed to the RTO is located in Section 7.4.

Hourly Emissions

Uncontrolled hourly CO_2 and CH_4 emissions from the TEG dehydrator that occur during RTO downtime are calculated using the ProMax® output for the waste stream. The following equation is used to estimate hourly CO_2 and CH_4 emission rates from the TEG dehydrator:

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{ProMax Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

The ProMax® simulation output file for the TEG dehydrator is provided in Appendix A for reference.

Annual Emissions

Annual emission rates for uncontrolled CO_2 and CH_4 during RTO downtime are estimated based on the hourly emission rate and expected RTO downtime frequency and duration, as shown in the following equation:

$$\text{Uncontrolled Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Number of events per Year}\left(\frac{\text{events}}{\text{yr}}\right) \times \text{Duration of event}\left(\frac{\text{hr}}{\text{events}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.4. REGENERATIVE THERMAL OXIDIZER

The Longhorn Gas Plant will be equipped with one RTO (EPN 5) to control emissions from the amine unit and glycol dehydrator. GHG emissions of CO_2, CH_4, and N_2O from the RTO will result from the combustion of the amine still vent (FIN 15) and TEG dehydrator (FIN 2) waste streams. Additionally, the RTO will utilize a gas-fired burner system during startup.

7.4.1. RTO Normal Operations

Uncontrolled GHG emissions from the amine still vent and the glycol dehydrator are estimated using ProMax® 3.2, as discussed in Sections 7.2 and 7.3 of this application. The waste stream rates and characteristics obtained from the ProMax® output are used as the gas inlet to the RTO.

Hourly Emissions of Combusted CO_2, CH_4, and N_2O

Controlled hourly emission rates for CO_2 and CH_4 from the RTO are estimated using the inlet to RTO data using the ProMax® output for the waste stream and the guaranteed destruction efficiency.

The following equation is used to estimate hourly CO_2 and CH_4 emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet to RTO}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency}(\%)]$$

Hourly N_2O emission rates are estimated using Equation W-40 in 40 CFR Subpart W for combustion units that combust process vent gas, as shown in the following equation:[7]

$$\begin{aligned} &\text{N}_2\text{O Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \\ &\quad = \text{Wate Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \frac{1\text{ day}}{24\text{ hr}} \times \frac{10^6\text{ scf}}{1\text{ MMscf}} \times \text{Process Gas HHV}\left(\frac{\text{MMBtu}}{\text{scf}}\right) \\ &\quad \times \text{N}_2\text{O Emission Factor}\left(\frac{\text{kg}}{\text{MMBtu}}\right) \times \frac{2.2046\text{ lb}}{1\text{ kg}} \end{aligned}$$

The process gas higher heating value (HHV) is taken from 40 CFR §98.233(z)(2)(vi). The N_2O emission factor is obtained from Table C-2 in 40 CFR Part 98 Subpart C for natural gas.

Hourly Emissions from Conversion to CO_2

In addition to emissions from combusted CO_2, CH_4, and N_2O, additional GHG emissions will result from the conversion of carbon atoms in the fuel to CO_2. For sources that combust process vent gas, the converted emissions are estimated based on Equations W-39A and W-39B obtained from 40 CFR 98 Subpart W.[8] The following equation is used to determine the CO_2 emissions resulting from the oxidation of methane (compounds with one carbon atom), ethane (compounds with two carbon atoms), propane (compounds with three carbon atoms), butanes (compounds with four carbon atoms), and pentanes+ (compounds with five or more carbon atoms):

[7] 40 CFR §98.233(z)(2)(vi).

[8] 40 CFR §98.233(z)(2)(iii).

$$\text{Converted } CO_2 \text{ Hourly Emission Rate} = \text{Inlet to RTO}\left(\frac{\text{lb}}{\text{hr}}\right) \text{ x Carbon Count x Desruction Rate Efficiency (\%)}$$

Annual Emissions

All annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr, using the following equation:

$$\text{Controlled Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.4.2. RTO Startup Operations

The RTO may periodically be shutdown for planned maintenance activities. The RTO will utilize a gas-fired burner system (EPN 5-MSS) to bring the RTO up to combustion temperature during startup. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine and dehydrator waste streams alone to support combustion. Emissions from the startup burner system will result from the combustion of pipeline quality natural gas. No emissions are expected from the RTO during shutdown or maintenance activities. Emissions from the amine and dehydrator streams during RTO downtime are addressed in Sections 7.2 and 7.3, respectively.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule and as shown in Table 7.1-1.[9]

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the RTO startup burner. Annual emission rates are estimated based on hourly emissions and the expected startup duration frequency. The following equations are used to estimate hourly and annual CO_2, CH_4, and N_2O emission rates from the RTO startup burner:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours per Event}\left(\frac{\text{hr}}{\text{event}}\right) \times \text{Events per Year}\left(\frac{\text{event}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

7.5. FLARE

The flare (EPN 6) will be used to destroy the off-gas produced during emergency situations, pigging, and electric-driven compressor blowdowns. Emissions from emergency events are not included in this application since they are non-routine.

GHG emissions of CO_2, CH_4, and N_2O from the flare will result from the combustion of pipeline quality natural gas in the pilot (EPN 6) and the combustion of gas vented during pigging and electric-driven compressor blowdowns (EPN

[9] 40 CFR Subpart C, Tables C-1 and C-2.

6-MSS). Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flowrate, and the residue gas analysis. Emissions from combusting gas vented during pigging operations are estimated using the expected gas volume and the inlet gas analysis. It is expected that the entire gas volume vented during pigging will be routed to the flare. However, a small portion of gas may be vented to the atmosphere, as discussed in Section 7.9. Emissions from residue compressor blowdown gas combustion are estimated using the expected blowdown gas volume and the residue gas analysis. Emissions from refrigeration compressor blowdown gas combustion are estimated using the expected blowdown gas volume and refrigerant propane composition.

GHG emissions are estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Reporting Rule and as shown in Table 7.1-1.[10]

Pilot Gas Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the heat input rating (MMBtu/hr) for the pilot flare. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following equations are used to estimate hourly and annual emission rates from the pilot flare:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

MSS Emissions

Hourly emission rates for CO_2, CH_4, and N_2O are based on the gas stream heat input rating (MMBtu/hr) for the gas from the maintenance activities. Annual emission rates are based on the annual gas stream heat input rating (MMBtu/yr), as determined by the expected blowdown frequency, duration, and gas volume. The following equations are used to estimate hourly and annual emission rates from MSS activities routed to the flare:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{yr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

7.6. ATMOSPHERIC STORAGE TANKS

The proposed Longhorn Gas Plant includes the following list of tanks:

[10] 40 CFR Subpart C, Tables C-1 and C-2.

Table 7.6-1. Atmospheric Storage Tanks Located at Longhorn Gas Plant

EPN	Tank Description	Tank Size (gal)
9	TEG Tank TEG Storage 210 bbl	8,820
10	Hot Oil Tank Hot Oil Storage 210 bbl	8,820
11	MEOH-1 Methanol Storage	1,000
12	Amine Tank Amine Storage 10 bbl	420
13	Lube Oil Tank-1 3612 Oil 100 bbl	4,200
14	Lube Oil Tank-2 Ref Oil 100 bbl	4,200
16	Wastewater Tank 210 bbl	8,820
17	Low Pressure Condensate Tank-1 210 bbl	8,820
18	Low Pressure Condensate Tank-2 210 bbl	8,820

Tanks 9, 10, 12, 13, and 14 have both a low vapor pressure and low throughput. Therefore, based on engineering judgment, the GHG emissions for these tanks are assumed negligible. Tank 11 contains methanol, which is not a source of GHG emissions. Additionally, according to the condensate analysis included in Appendix B, there are no GHG weight fractions in the detectable range of the condensate sample. Therefore, GHG emissions from Tanks 16, 17, and 18 are assumed negligible.

7.7. TRUCK LOADING LOSSES

The produced water and condensate tanks contents (Tanks 16, 17, and 18) will be removed from the site via truck. However, according to the condensate analysis included in Appendix B, there are no GHG weight fractions in the detectable range of the sample. Therefore, GHG emissions from truck loading are assumed negligible.

7.8. EQUIPMENT LEAK FUGITIVES

Process fugitive GHG emissions result from leaking components such as valves and flanges and from sampling equipment used to evaluate the gas streams at the plant such as gas chromatographs and O_2 sensors (EPN FUG-1).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment at the Longhorn Gas Plant, the GHG content of each stream for which component counts are placed in service, and emission factors for each component type taken from the TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.[11] Targa has selected the 28 VHP Monitoring Program, and these control efficiencies are applied to the equipment leak fugitive calculations. The representative gas and liquid analyses used in the fugitive calculations are provided in Appendix B.

<u>Hourly Emissions</u>

Hourly emissions of GHG from traditional fugitive components (i.e., valves, pumps, flanges, compressors, relief valves, and connectors) are estimated using TCEQ emission factors, component counts, and the GHG content of each stream. The following equation is used to estimate hourly CO_2 and CH_4 emissions:

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[11] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

$$\text{Hourly Emission Rate (lb/hr)} = \text{TCEQ Emission Factor}\left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{Number of Components (\# comp)} \times \text{Compound Content (wt \%)} \times \text{28 VHP Control Factor(\%)}$$

Hourly emissions of CO_2 and CH_4 from O_2 sensors and gas chromatographs are estimated based on the leak rate of the components and the speciated gas analysis for each stream, as shown in the following equation:

$$\text{Hourly Emission Rate (lb/hr)} = \text{Leak Rate}\left(\frac{\text{scf}}{\text{hr}}\right) \times \text{Compound Molecular Weight}\left(\frac{\text{lb}}{\text{lb-mol}}\right) \times \left(\frac{\text{lb} - \text{mol}}{\text{379.5 scf}}\right) \times \text{Number of Components} \times \text{Compound Content (wt \%)}$$

Annual Emissions

Annual emissions are estimated based on hourly emissions rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

7.9. FUGITIVE MSS ACTIVITIES

Additional fugitive MSS activities are included in this application that may occur at the Longhorn Gas Plant. These emissions include pigging, meters, and truck unloading of refrigerant propane and will be vented directly to the atmosphere (EPNs 7-MSS, 8-MSS, and FUG-MSS). The calculation of emissions is based on the frequency of the event, the event duration, the amount vented during each event, and the CO_2 and CH_4 content of the stream vented. Note that there are no GHG emissions from truck unloading of refrigerant propane.

Hourly Emissions

The following equation is used to estimate speciated hourly VOC emission rates from the gaseous MSS activities (i.e., pigging and meters) for each compound in the stream. For events expected to last less than one hour, it is assumed that no more than one event occurs per hour.

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Gas Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Compound Content (mol \%)} \times \text{Compound Molecular Weight}\left(\frac{\text{lb}}{\text{lb-mol}}\right) \times \left(\frac{\text{lb-mol}}{\text{379.5 scf}}\right)$$

Annual Emissions

Annual VOC emission rates from all MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Event Frequency}\left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

Site-Wide Emission Summary for Greenhouse Gas Pollutants

Normal Operations Summary

EPN	FIN	Description	Hourly Emissions (lb/hr)				Annual Emissions (tpy)			
			CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
1	1	TEG-1 Glycol Reboiler	233.78	4.40E-03	4.00E-04	234.00	1,023.96	0.02	1.80E-03	1,024.92
2	2	TEG Dehydrator During RTO Downtime	0.02	3.13	--	65.81	1.86E-03	0.24	--	5.00
3	3	HTR-1 Regen Heater	1,449.44	0.03	2.70E-03	1,450.91	6,348.55	0.13	0.01	6,354.99
4	4	HTR-2 Hot Oil Heater	11,455.22	0.22	0.02	11,466.44	50,173.86	0.94	0.09	50,223.01
5	2, 15	RTO-1 Regen Thermal Oxidizer	26,522.86	0.29	0.07	26,550.65	116,170.13	1.27	0.31	116,291.83
6	6	Flare-1 Flare (Pilot)	17.53	3.30E-04	3.30E-05	17.55	76.80	1.45E-03	1.45E-04	76.87
15	15	Amine Still Vent During RTO Downtime	26,131.43	25.97	--	26,676.83	1,985.99	1.97	--	2,027.44
16	16	Produced Water Tank 210 bbl	--	--	--	--	--	--	--	--
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	--	--	--	--	--	--
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	--	--	--	--	--	--
21	21	Open Drain Sump	--	--	--	--	--	--	--	--
FUG-1	FUG-1	Plant-wide Fugitive Components	0.34	4.29	--	90.38	1.49	18.78	--	395.86
FUG-2	FUG-2	Truck Loading	--	--	--	--	--	--	--	--
		Total Normal Operations Emissions	**65,810.63**	**33.93**	**0.09**	**66,552.56**	**175,780.78**	**23.36**	**0.41**	**176,399.93**

MSS Operations Summary [1]

EPN	FIN	Description	Hourly Emissions (lb/hr)				Annual Emissions (tpy)			
			CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
5-MSS	5-MSS	RTO-1 Startup	350.67	6.60E-03	6.60E-04	351.01	1.40	2.64E-05	2.64E-06	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	1,631.17	0.06	9.46E-03	1,635.26	9.85	2.95E-04	4.73E-05	9.87
7-MSS	7-MSS	PR-1 16" Reciever	0.46	3.32	--	70.17	0.01	0.09	--	1.82
8-MSS	8-MSS	PR-2 12" Reciever	0.46	3.32	--	70.17	0.01	0.09	--	1.82
20-MSS	20-MSS	Refrigerant Unloading	--	--	--	--	--	--	--	--
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	0.73	5.21	--	110.17	8.72E-03	0.06	--	1.32
		Total MSS Emissions	**1,983.49**	**11.91**	**0.01**	**2,236.78**	**11.29**	**0.24**	**4.99E-05**	**16.24**

[1] FUG-MSS does not include pigging or refrigerant unloading since those activities have separate EPNs.

Total Operations Summary

Description	Hourly Emissions (lb/hr) [1]				Annual Emissions (tpy)			
	CO_2	CH_4	N_2O	CO_2e	CO_2	CH_4	N_2O	CO_2e
Normal Operations	65,810.63	33.93	0.09	66,552.56	175,780.78	23.36	0.41	176,399.93
MSS Activities	1,983.49	11.91	0.01	2,236.78	11.29	0.24	4.99E-05	16.24
Total Site-wide Emissions	**135,196.43**	**116.45**	**0.14**	**137,685.08**	**175,792.07**	**23.59**	**0.41**	**176,416.17**

[1] Some MSS emissions may occur at the same time as normal operation. For example, RTO startup (EPN 5-MSS) does not occur at the same time as RTO normal operation (EPN 5). In these cases, the total hourly emissions are calculated based on the maximum emission rates between MSS and normal operation scenarios.

Natural Gas External Combustion Units (EPNs 1, 3, 4)

Input Data

Heating Value of Natural Gas (Btu/scf)	1,000
Hours of Operation (hrs/yr)	8,760

Natural Gas External Combustion Greenhouse Gas Emission Factors

Units [1]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
Global Warming Potential (GWP) [2]	1	21	310
lb/MMBtu [3]	116.89	2.20E-03	2.2E-04

[1] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

[2] Global warming potentials obtained from 40 CFR 98 Subpart A Table A-1.

[3] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:

Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

Example CO_2 Emission Factor (lb/MMBtu) = $\frac{53.02\ \text{kg}}{\text{MMBtu}} \times \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{116.89\ \text{lb}}{\text{MMBtu}}$

Natural Gas External Combustion Greenhouse Gas Emission Rates [1, 2, 3]

Description	EPN	Heat Input Rating (MMBtu/hr)	CO_2 Hourly (lb/hr)	CO_2 Annual (tpy)	CH_4 Hourly (lb/hr)	CH_4 Annual (tpy)	N_2O Hourly (lb/hr)	N_2O Annual (tpy)	CO_2e Hourly (lb/hr)	CO_2e Annual (tpy)
TEG-1 Glycol Reboiler	1	2.0	233.78	1,023.96	4.40E-03	0.02	4.00E-04	1.80E-03	234.00	1,024.92
HTR-1 Regen Heater	3	12.4	1,449.44	6,348.55	0.03	0.13	2.70E-03	0.01	1,450.91	6,354.99
HTR-2 Hot Oil Heater	4	98.0	11,455.22	50,173.86	0.22	0.94	0.02	0.09	11,466.44	50,223.01
		Total Emissions	**13,138.44**	**57,546.37**	**0.25**	**1.09**	**0.02**	**0.11**	**13,151.35**	**57,602.92**

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{2.00\ \text{MMBtu}}{\text{hr}} \times \frac{53.02\ \text{lb}}{\text{MMBtu}} = \frac{233.78\ \text{lb}}{\text{hr}}$

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{233.78\ \text{lb}}{\text{hr}} \times 1 + \frac{4.40\text{E-03}\ \text{lb}}{\text{hr}} \times 21 + \frac{4.00\text{E-04}\ \text{lb}}{\text{hr}} \times 310 = \frac{234.00\ \text{lb}}{\text{hr}}$

[3] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{233.78\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1{,}023.96\ \text{ton}}{\text{yr}}$

RTO (EPNs 5, 5-MSS)

RTO Greenhouse Gas Summary [1]

Description	EPN	CO_2 Hourly (lb/hr)	CO_2 Annual (tpy)	CH_4 Hourly (lb/hr)	CH_4 Annual (tpy)	N_2O Hourly (lb/hr)	N_2O Annual (tpy)	CO_2e Hourly (lb/hr)	CO_2e Annual (tpy)
RTO - Normal Operation	5	26,522.86	116,170.13	0.29	1.27	0.07	0.31	26,550.65	116,291.83
RTO - Startup	5-MSS	350.67	1.40	6.60E-03	2.64E-05	6.60E-04	2.64E-06	351.01	1.40
	Total	26,873.53	116,171.54	0.30	1.27	0.07	0.31	26,901.66	116,293.24

[1] Total RTO emissions based on emission estimates for each inlet stream to RTO.

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Amine Acid Gas Combustion

Input Data

Maximum Amine Acid Gas Flowrate [1] = 5.76 MMscfd (wet)

Hours of Operation = 8,760 hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Number of Carbon Atoms	Composition [1] (mol %)	DRE [3] (%)	Inlet to RTO [4] (lb/hr)	Controlled GHG Emissions [5, 6] (lb/hr)	Controlled GHG Emissions [5, 6] (tpy)	Converted to CO_2 [6, 7] (lb/hr)	Converted to CO_2 [6, 7] (tpy)
Carbon Dioxide	1	93.84004373	0%	26,131.43	26,131.43	114,455.68	--	--
Methane	1	0.25585299	99%	25.97	0.26	1.14	25.71	112.62
Ethane	2	0.06714017	99%	12.77	--	--	25.29	110.78
Propane	3	0.01608316	99%	4.49	--	--	13.33	58.37
Butanes [8]	4	0.00566657	99%	2.08	--	--	8.25	36.15
Pentanes +	5	0.02204995	99%	11.97	--	--	59.25	259.50
							Total GHG Emissions [6] (lb/hr)	**Total GHG Emissions [6] (tpy)**
CO_2 [9]							26,263.27	115,033.10
CH_4 [10]							0.26	1.14
N_2O [11]							0.07	0.29
CO_2e [12]							26,288.99	115,145.76

[1] Maximum amine acid gas flowrate and composition data based on amine acid gas stream from ProMax output data.

[2] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[3] Destruction efficiency per manufacturer.

[4] Hourly inlet to RTO based on amine acid gas stream from ProMax output data.

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

Example Controlled Methane Hourly Emission Rate (lb/hr) = 25.97 lb / hr | (1 - 0.99) = 0.26 lb / hr

[6] Annual Emission Rate (tpy) = Controlled Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example Controlled CO_2 Annual Emission Rate (tpy) = 26,131.43 lb / hr | 8,760 hr / yr | 1 ton / 2,000 lb = 114,455.68 tpy

[7] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO_2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to RTO (lb/hr) x DRE (%) x Carbon Count (#)

Example CH_4 Converted to CO_2 Hourly Emission Rate (lb/hr) = 25.97 lb / hr | 99 % | 1 = 25.71 lb / hr

[8] Piperazine has 4 carbon atoms and therefore is included in the Butane total composition.

[9] Total CO_2 is the sum of controlled CO_2 emissions plus the CO_2 emissions from the oxidation of other carbon compounds in the combustion stream.

[10] Total CH_4 is sum of controlled CH_4 emissions.

[11] Per 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the N_2O emissions.

Hourly Emission Rate for N_2O (lb/hr) = Acid Gas Flowrate (MMscf/day) x (day / 24 hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (kg/MMBtu) x (2.2046 lb/kg)

Example Hourly Emission Rate for N_2O (lb/hr) = 5.76 MMscf / day | 1 day / 24 hrs | 10^6 scf / 1 MMscf | 1.235E-03 MMBtu / scf | 1.00E-04 kg / MMBtu | 2.2046 lb / kg = 6.54E-02 lb / hr

[12] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = 26,263.27 lb / hr | 1 + 0.26 lb / hr | 21 + 6.54E-02 lb / hr | 310 = 26,288.99 lb / hr

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Dehydrator Waste Gas Combustion

Input Data

Maximum Dehydrator Waste Gas Flowrate [1] =	0.40	MMscfd (wet)
Hours of Operation =	8,760	hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Number of Carbon Atoms	Composition [1] (mol %)	DRE [3] (%)	Inlet to RTO [4] (lb/hr)	Controlled GHG Emissions [5, 6] (lb/hr)	Controlled GHG Emissions [5, 6] (tpy)	Converted to CO_2 [6, 7] (lb/hr)	Converted to CO_2 [6, 7] (tpy)
Carbon Dioxide	1	0.00126829	0%	0.02	0.02	0.11	--	--
Methane	1	0.44455652	99%	3.13	0.03	0.14	3.10	13.58
Ethane	2	0.43008969	99%	5.68	--	--	11.25	49.26
Propane	3	0.45586158	99%	8.83	--	--	26.22	114.85
Butanes	4	0.31166393	99%	7.96	--	--	31.51	138.00
Pentanes +	5	0.99635554	99%	37.88	--	--	187.50	821.23
							Total GHG Emissions [6] (lb/hr)	**Total GHG Emissions [6] (tpy)**
CO_2 [8]							259.60	1,137.03
CH_4 [9]							0.03	0.14
N_2O [10]							4.54E-03	0.02
CO_2e [11]							261.66	1,146.07

[1] Maximum dehydrator waste gas flowrate and composition data based on the dehydrator waste gas stream from ProMax output data.

[2] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[3] Destruction efficiency per manufacturer.

[4] Hourly inlet to RTO based on dehydrator waste gas stream from ProMax output data.

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

Example Controlled Methane Hourly Emission Rate (lb/hr) = $\frac{03.13\ \text{lb}}{\text{hr}} \times (1 - 0.99) = \frac{0.03\ \text{lb}}{\text{hr}}$

[6] Annual Emission Rate (tpy) = Controlled Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example Controlled CO_2 Annual Emission Rate (tpy) = $\frac{0.02\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 0.11\ \text{tpy}$

[7] During combustion, hydrocarbons in the acid gas waste stream are oxidized to form CO2 and water vapor.

Per 40 CFR Part 98.233(z)(2)(iii) (Subpart W), for combustion units that combust process vent gas, equation W-39A and W-39B are used to estimate the GHG emissions from additional carbon compounds in the waste gas.

Hourly Emission Rate for Compounds Converted to CO_2 (lb/hr) = Inlet to RTO (lb/hr) x DRE (%) x Carbon Count (#)

Example Converted Methane Hourly Emission Rate (lb/hr) = $\frac{3.13\ \text{lb}}{\text{hr}} \times 99\ \% \times 1 = \frac{3.10\ \text{lb}}{\text{hr}}$

[8] Total CO_2 is the sum of controlled CO_2 emissions plus the CO_2 emissions from the oxidation of other carbon compounds in the combustion stream.

[9] Total CH_4 is sum of controlled CH_4 emissions.

[10] Per 40 CFR Part 98.233(z)(2)(vi) (Subpart W), for combustion units that combust process vent gas, equation W-40 is used to estimate the GHG emissions.

Hourly Emission Rate for N_2O (lb/hr) = Waste Gas Flowrate (MMscf/day) x (day / 24 hr) x (10^6 scf / 1 MMscf) x Subpart W Process Gas HHV (MMBtu/scf) x Emission Factor (kg/MMBtu) x (2.2046 lb/kg)

Example Hourly Emission Rate for N_2O (lb/hr) = $\frac{0.40\ \text{MMscf}}{\text{day}} \times \frac{1\ \text{day}}{24\ \text{hrs}} \times \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \times \frac{1.235\text{E-03 MMBtu}}{\text{scf}} \times \frac{1.00\text{E-04 kg}}{\text{MMBtu}} \times \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{4.54\text{E-03 lb}}{\text{hr}}$

[11] CO_2e emissions based on GWPs for each greenhouse gas pollutant

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{259.60\ \text{lb}}{\text{hr}} \times 1 + \frac{0.03\ \text{lb}}{\text{hr}} \times 21 + \frac{4.54\text{E-03 lb}}{\text{hr}} \times 310 = \frac{261.66\ \text{lb}}{\text{hr}}$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Greenhouse Gases - Startup [1]

Input Data

Startup Burner Size =	3 MMBtu/hr
Startup Event Duration =	2 hr/event
Startup Event Frequency =	4 events/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors

Units [2]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.0E-03	1.0E-04
GWP [3]	1	21	310
lb/MMBtu [4]	116.89	2.20E-03	2.20E-04

[1] There will be GHG emissions associated with using a gas-fired burner system to bring the unit up to combustion temperature during startup.
The startup burner will combust pipeline quality sweet natural gas
After the system has reached temperature, the burner will be shut off and the system will function using the energy content of the waste stream alone to support combustion.

[2] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

[3] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[4] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:

Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

Example CO_2 Emission Factor (lb/MMBtu) = $\frac{53.02 \text{ kg}}{\text{MMBtu}} \times \frac{2.2046 \text{ lb}}{\text{kg}} = \frac{116.89 \text{ lb}}{\text{MMBtu}}$

Compound	RTO Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	350.67	1.40
CH_4	6.60E-03	2.64E-05
N_2O	6.60E-04	2.64E-06
CO_2e	351.01	1.40

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Startup Burner Size (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{3 \text{ MMBtu}}{\text{hr}} \times \frac{116.89 \text{ lb}}{\text{MMBtu}} = \frac{350.67 \text{ lb}}{\text{hr}}$

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{350.67 \text{ lb}}{\text{hr}} \times 1 + \frac{6.60\text{E-03 lb}}{\text{hr}} \times 21 + \frac{6.60\text{E-04 lb}}{\text{hr}} \times 310 = \frac{351.01 \text{ lb}}{\text{hr}}$

[3] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Startup Event Duration (hr/event) x Startup Event Frequency (events/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{350.67 \text{ lb}}{\text{hr}} \times \frac{2 \text{ hr}}{\text{event}} \times \frac{4 \text{ events}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{1.40 \text{ ton}}{\text{yr}}$

Amine Still Vent (EPN 15)

Amine Still Vent Emissions During Scheduled RTO Downtime - Greenhouse Gases [1]

Input Data

Scheduled RTO downtime duration =	38	hr/event
Scheduled RTO downtime frequency =	4	events/yr
Hours of Operation =	152	hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Amine Still Vent Emissions	
	(lb/hr) [3, 4]	(tpy) [5]
CO_2	26,131.43	1,985.99
CH_4	25.97	1.97
N_2O	--	--
CO_2e	26,676.83	2,027.44

[1] During scheduled RTO downtime, the amine acid gas stream will be vented to the atmosphere.

[2] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[3] Maximum Potential Hourly Emission Rate (lb/hr) taken from ProMax output data.

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{26{,}131.43 \text{ lb}}{\text{hr}} \times 1 + \frac{25.97 \text{ lb}}{\text{hr}} \times 21 = \frac{26{,}676.83 \text{ lb}}{\text{hr}}$

[5] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Downtime Event Duration (hr/event) x Downtime Event Frequency (events/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{26{,}131.43 \text{ lb}}{\text{hr}} \times \frac{38 \text{ hr}}{\text{event}} \times \frac{4 \text{ events}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{1{,}985.99 \text{ ton}}{\text{yr}}$

TEG Dehydrator Vent (EPN 2)

Dehydrator Vent Emissions During Scheduled RTO Downtime - Greenhouse Gases [1]

Input Data

Scheduled RTO downtime duration =	38	hr/event
Scheduled RTO downtime frequency =	4	events/yr
Hours of Operation =	152	hrs/yr

Global Warming Potentials [2]

CO_2	CH_4	N_2O
1	21	310

Compound	Dehydrator Vent Emissions	
	(lb/hr) [3, 4]	(tpy) [5]
CO_2	0.02	1.86E-03
CH_4	3.13	0.24
N_2O	--	--
CO_2e	65.81	5.00

[1] During scheduled RTO downtime, the dehydrator condenser outlet stream will be vented to the atmosphere.

[2] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[3] Maximum Potential Hourly Emission Rate (lb/hr) taken from ProMax output data.

[4] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{2.45\text{E-}02 \text{ lb}}{\text{hr}} \times 1 + \frac{3.13 \text{ lb}}{\text{hr}} \times 21 = \frac{65.81 \text{ lb}}{\text{hr}}$

[5] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Downtime Event Duration (hr/event) x Downtime Event Frequency (events/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{2.45\text{E-}02 \text{ lb}}{\text{hr}} \times \frac{38 \text{ hr}}{\text{event}} \times \frac{4 \text{ events}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{1.86\text{E-}03 \text{ ton}}{\text{yr}}$

Flare (EPNs 6, 6-MSS)

Flare Greenhouse Gas Summary [1]

Description	EPN	CO_2 Hourly (lb/hr)	CO_2 Annual (tpy)	CH_4 Hourly (lb/hr)	CH_4 Annual (tpy)	N_2O Hourly (lb/hr)	N_2O Annual (tpy)	CO_2e Hourly (lb/hr)	CO_2e Annual (tpy)
Flare - Pilot Gas	6	17.53	76.80	3.30E-04	1.45E-03	3.30E-05	1.45E-04	17.55	76.87
Flare - MSS	6-MSS	1,631.17	9.85	5.50E-02	2.95E-04	9.46E-03	4.73E-05	1,635.26	9.87
	Total	1,648.70	86.65	0.06	1.74E-03	9.49E-03	1.92E-04	1,652.81	86.75

[1] Total flare emissions based on emission estimates for each inlet stream to the flare.

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Input Data

Gas Stream Heat Value =	1,000	Btu/scf
Number of Pilots =	3	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	150	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.314	MMscf/yr
Gas Stream Heat Input [3] =	0.15	MMBtu/hr
Gas Stream Heat Input [4] =	1,314	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors [5]

Units [6]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP [7]	1	21	310
lb/MMBtu [8]	116.89	2.20E-03	2.20E-04

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

$$\text{Hourly Flowrate (scf/hr)} = \frac{50.0\text{ scf}}{\text{hr-pilot}} \times 3 = \frac{150\text{ scf}}{\text{hr}}$$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10[6] scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{1.314\text{ MMscf}}{\text{yr}}$$

[3] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10[6] scf)

$$\text{Example Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{1{,}000\text{ Btu}}{\text{scf}} \times \frac{1\text{ MMBtu}}{10^6\text{ Btu}} \quad \frac{0.15\text{ MMBtu}}{\text{hr}}$$

[4] Annual Gas Stream Heat Input (MMBtu/yr) = Hourly Gas Stream Heat Input (MMBtu/hr) x Hours of Operation (hrs/yr)

$$\text{Example Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.15\text{ MMBtu}}{\text{hr}} \times \frac{8{,}760\text{ hrs}}{\text{yr}} = \frac{1{,}314\text{ MMBtu}}{\text{yr}}$$

[5] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[6] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

[7] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[8] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:

Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

$$\text{Example } CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{53.02\text{ kg}}{\text{MMBtu}} \times \frac{2.2046\text{ lb}}{\text{kg}} = \frac{116.89\text{ lb}}{\text{MMBtu}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - Greenhouse Gases

Compound	Flare Emissions [1, 2, 3] (lb/hr)	Flare Emissions [1, 2, 3] (tpy)
CO_2	17.53	76.80
CH_4	3.30E-04	1.45E-03
N_2O	3.30E-05	1.45E-04
CO_2e	17.55	76.87

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Pilot Size (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{0.15 \text{ MMBtu}}{\text{hr}} \cdot \frac{116.89 \text{ lb}}{\text{MMBtu}} = \frac{17.53 \text{ lb}}{\text{hr}}$

[2] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{17.53 \text{ lb}}{\text{hr}} \cdot \frac{8,760 \text{ hr}}{\text{yr}} \cdot \frac{1 \text{ ton}}{2,000 \text{ lb}} = \frac{76.80 \text{ ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{17.53 \text{ lb}}{\text{hr}} \cdot 1 + \frac{3.30\text{E-04 lb}}{\text{hr}} \cdot 21 + \frac{3.30\text{E-05 lb}}{\text{hr}} \cdot 310 = \frac{17.55 \text{ lb}}{\text{hr}}$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - Greenhouse Gases [1]

<u>Input Data</u>

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2] =	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input [5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input [6] =	54.00	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors [7]

Units [8]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP [9]	1	21	310
lb/MMBtu [10]	116.89	2.20E-03	2.20E-04

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shudown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{\text{event}}{1\ \text{hr}} \cdot 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{9\ \text{events}}{\text{yr}} \cdot \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6000\ \text{scf}}{\text{hr}} \cdot \frac{1{,}000\ \text{Btu}}{\text{scf}} \cdot \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{6.00\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \cdot \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{54.00\ \text{MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

[9] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[10] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:
Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

$$\text{Example } CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{53.02\ \text{kg}}{\text{MMBtu}} \cdot \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{116.89\ \text{lb}}{\text{MMBtu}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - Greenhouse Gases [1]

Compound	Flare Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	701.34	3.16
CH_4	0.01	5.94E-05
N_2O	1.32E-03	5.94E-06
CO_2e	702.03	3.16

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Hourly Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = $\frac{6.00\text{ MMBtu}}{\text{hr}} \times \frac{116.89\text{ lb}}{\text{MMBtu}} = \frac{701.34\text{ lb}}{\text{hr}}$

[2] Maximum Potential Annual Emission Rate (tpy) = Annual Heat Input (MMBtu/yr) x Emission Factor (lb/MMBtu) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = $\frac{54.00\text{ MMBtu}}{\text{yr}} \times \frac{116.89\text{ lb}}{\text{MMBtu}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{3.16\text{ ton}}{\text{yr}}$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{701.34\text{ lb}}{\text{hr}} \times 1 + \frac{1.32\text{E-02 lb}}{\text{hr}} \times 21 + \frac{1.32\text{E-03 lb}}{\text{hr}} \times 310 = \frac{702.03\text{ lb}}{\text{hr}}$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - Greenhouse Gases [1]

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2]=	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input [5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input [6] =	54.00	MMBtu/yr

Propane External Combustion Greenhouse Gas Emission Factors [7]

Units [8]	CO_2	CH_4	N_2O
kg/MMBtu	61.46	3.00E-03	6.00E-04
GWP [9]	1	21	310
lb/MMBtu [10]	135.49	6.60E-03	1.32E-03

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shudown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \Big| \frac{\text{event}}{1\ \text{hr}} \Big| \frac{3\ \text{compressors}}{} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10[6] scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \Big| \frac{9\ \text{events}}{\text{yr}} \Big| \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10[6] scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6000\ \text{scf}}{\text{hr}} \Big| \frac{1{,}000\ \text{Btu}}{\text{scf}} \Big| \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{6.00\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \Big| \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{54.00\ \text{MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for propane gas.

[9] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[10] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:
Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

$$\text{Example } CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{61.46\ \text{kg}}{\text{MMBtu}} \Big| \frac{2.2046\ \text{lb}}{\text{kg}} = \frac{135.49\ \text{lb}}{\text{MMBtu}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - Greenhouse Gases [1]

Compound	Flare Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	812.94	3.66
CH_4	0.04	1.78E-04
N_2O	7.92E-03	3.56E-05
CO_2e	816.23	3.67

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Hourly Heat Input (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) =
$$\frac{6.00\ \text{MMBtu}}{\text{hr}} \times \frac{135.49\ \text{lb}}{\text{MMBtu}} = \frac{812.94\ \text{lb}}{\text{hr}}$$

[2] Maximum Potential Annual Emission Rate (tpy) = Annual Heat Input (MMBtu/yr) x Emission Factor (lb/MMBtu) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) =
$$\frac{54.00\ \text{MMBtu}}{\text{yr}} \times \frac{135.49\ \text{lb}}{\text{MMBtu}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{3.66\ \text{ton}}{\text{yr}}$$

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) =
$$\frac{812.94\ \text{lb}}{\text{hr}} \times 1 + \frac{3.96\text{E-}02\ \text{lb}}{\text{hr}} \times 21 + \frac{7.92\text{E-}03\ \text{lb}}{\text{hr}} \times 310 = \frac{816.23\ \text{lb}}{\text{hr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging - Greenhouse Gases [1]

Input Data

	Pigging 12"	Pigging 16"	
Annual Number of Events =	52	52	events/year
Estimated Event Duration [2]=	1	1	hr/event
Event Flowrate =	360	640	scf/event
Annual Event Hours =	52	52	hrs/yr
Gas Stream Heat Value =	1,000	1,000	Btu/scf
Hourly Flowrate [3] =	360	640	scf/hr
Annual Flowrate [4] =	0.019	0.033	MMscf/yr
Hourly Gas Stream Heat Input [5] =	0.36	0.64	MMBtu/hr
Annual Gas Stream Heat Input [6] =	18.72	33.28	MMBtu/yr

Natural Gas External Combustion Greenhouse Gas Emission Factors [7]

Units [8]	CO_2	CH_4	N_2O
kg/MMBtu	53.02	1.00E-03	1.00E-04
GWP [9]	1	21	310
lb/MMBtu [10]	116.89	2.20E-03	2.20E-04

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{\text{0,360 scf}}{\text{event}} \times \frac{\text{event}}{\text{1 hr}} = \frac{\text{360 scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{\text{0,360 scf}}{\text{event}} \times \frac{\text{52 events}}{\text{yr}} \times \frac{\text{1 MMscf}}{10^6\text{ scf}} = \frac{\text{0.019 MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{\text{360 scf}}{\text{hr}} \times \frac{\text{1,000 Btu}}{\text{scf}} \times \frac{\text{1 MMBtu}}{10^6\text{ Btu}} \quad \frac{\text{0.36 MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{\text{0.019 MMscf}}{\text{yr}} \times \frac{\text{1,000 Btu}}{\text{scf}} = \frac{\text{18.72 MMBtu}}{\text{yr}}$$

[7] Per 40 CFR Part 98.233(z)(1) (Subpart W), if the fuel combusted in the stationary or portable equipment is listed in Table C-1 of Subpart C, then emissions are calculated per Subpart C.

[8] Emission factors obtained from 40 CFR 98 Subpart C Tables C-1 and C-2 for natural gas.

[9] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[10] Emission factors converted from kg/MMBtu to lb/MMBtu using the following conversion:
Greenhouse Gas Emission Factor (lb/MMBtu) = Greenhouse Gas Emission Factor (kg/MMBtu) x 2.2046 (lb/kg)

$$\text{Example } CO_2 \text{ Emission Factor (lb/MMBtu)} = \frac{\text{53.02 kg}}{\text{MMBtu}} \times \frac{\text{2.2046 lb}}{\text{kg}} = \frac{\text{116.89 lb}}{\text{MMBtu}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging - Greenhouse Gases [1]

Compound	Flare Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
CO_2	116.89	3.04
CH_4	2.20E-03	5.72E-05
N_2O	2.20E-04	5.72E-06
CO_2e	117.00	3.04

[1] Maximum Potential Hourly Emission Rate (lb/hr) = (Hourly Heat Input for the 12" Pipe +Hourly Heat Input for the 16" Pipe)(MMBtu/hr) x Emission Factor (lb/MMBtu)

Example CO_2 Hourly Emission Rate (lb/hr) = (0.36 MMBtu/hr + 0.64MMBtu/hr) | 116.89 lb / MMBtu = 116.89 lb / hr

[2] Maximum Potential Annual Emission Rate (tpy) = (Annual Heat Input for the 12" Pipe + Annual Heat Input for the 16" Pipe)(MMBtu/yr) x Emission Factor (lb/MMBtu) x (1 ton / 2,000 lb)

Example CO_2 Annual Emission Rate (tpy) = (18.72 MMBtu/yr + 33.28MMBtu/yr) | 116.89 lb / MMBtu | 1 ton / 2,000 lb = 3.04 ton / yr

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP + N_2O Emission Rate (lb/hr) x N_2O GWP

Example CO_2e Hourly Emission Rate (lb/hr) = 116.89 lb / hr | 1 + 2.20E-03 lb / hr | 21 + 2.20E-04 lb / hr | 310 = 117.00 lb / hr

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

MSS Activity Emissions Vented to Atmosphere - VOC

MSS Activity [1]	PM Events (events/yr)	Event Duration (hr/event)	Volume per Event (scf/event)	Associated Product Stream [2]
Meters	24	0.017	157	Inlet Gas
Pigging 12"	52	0.017	100	Inlet Gas
Pigging 16"	52	0.017	100	Inlet Gas
Truck Unloading Refrigerant Propane [3]	24	1	0.0055	Liquid Propane

[1] Does not include all MSS activities at the site. Although pigging is sent to the flare, a small portion may be released into the atmosphere during removal of the pig.
[2] Based on process flow diagram provided by Targa, pigging operations occur at the inlet gas stream.
[3] The liquid volume is based on the capacity of the hose nozzle, which has a length of 3 inches and a diameter of 2 inches.

Stream Speciation

Component	MW (lb/lb-mol)	Liquid Density [1] (lb/scf)	Product Stream Mole Percent (%) Inlet Gas [2]	Propane [3]
N_2	28.01		1.035	--
CO_2	44.01		3.952	--
H_2S	34.08		--	--
Methane	16.04		77.776	--
Ethane	30.07		9.811	--
Propane	44.10	31.64	4.508	100.000
i-Butane	58.12		0.491	--
n-Butane	58.12		1.219	--
i-Pentane	72.15		0.328	--
n-Pentane	72.15		0.341	--
n-Hexane	86.18		0.117	--
Hexane +	86.18		0.180	--
Benzene	78.11		0.008	--
Cyclohexane	84.16		0.025	--
i-Heptane	100.21		0.115	--
n-Heptane	100.21		0.031	--
Toluene	92.14		0.008	--
i-Octane	114.23		0.038	--
n-Octane	114.23		0.005	--
Ethylbenzene	106.17		--	--
m, o, p Xylene	106.16		0.002	--
i-Nonane	128.20		0.009	--
n-Nonane	128.20		0.001	--
i-Decane	142.29		0.001	--
n-Decane	142.29		--	--
i-Undecanes	156.31		0.001	--
Total VOC			7.43	100.00
Total HAP			0.14	--

[1] Per Hidnay, A. J. & Parrish, W. R. (2006). "Fundamentals of Natural Gas Processing." Taylor and Francis Group Publishing.
[2] Inlet gas composition is calculated from the combination of the New Harp and Waggoner gas streams that will be entering the Longhorn Plant. Provided by Targa to Trinity via email on 12/02/11.
[3] Refrigerant propane is 100% liquid propane.

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

Speciated Hourly Emissions

Component	Hourly Emissions (lb/hr) [1, 2]				
	Meters [3]	Pigging 12" [3]	Pigging 16" [3]	Truck Unloading Refrigerant Propane	Total
N_2	0.12	0.08	0.08	--	0.28
CO_2	0.73	0.46	0.46	--	1.65
H_2S	--	--	--	--	0.00E+00
Methane	5.21	3.32	3.32	--	11.85
Ethane	1.23	0.78	0.78	--	2.80
Propane	0.83	0.53	0.53	0.17	2.06
i-Butane	0.12	0.08	0.08	--	0.27
n-Butane	0.30	0.19	0.19	--	0.67
i-Pentane	0.10	0.06	0.06	--	0.22
n-Pentane	0.10	0.07	0.07	--	0.23
n-Hexane	0.04	0.03	0.03	--	0.10
Hexane +	0.06	0.04	0.04	--	0.15
Benzene	2.61E-03	1.66E-03	1.66E-03	--	5.93E-03
Cyclohexane	8.79E-03	5.60E-03	5.60E-03	--	0.02
i-Heptane	0.05	0.03	0.03	--	0.11
n-Heptane	0.01	8.26E-03	8.26E-03	--	0.03
Toluene	3.08E-03	1.96E-03	1.96E-03	--	7.00E-03
i-Octane	0.02	0.01	0.01	--	0.04
n-Octane	2.39E-03	1.52E-03	1.52E-03	--	5.42E-03
Ethylbenzene	--	--	--	--	0.00E+00
m, n, p Xylene	8.87E-04	5.65E-04	5.65E-04	--	2.02E-03
i-Nonane	4.82E-03	3.07E-03	3.07E-03	--	0.01
n-Nonane	5.35E-04	3.41E-04	3.41E-04	--	1.22E-03
i-Decane	5.94E-04	3.79E-04	3.79E-04	--	1.35E-03
n-Decane	--	--	--	--	0.00E+00
i-Undecanes	6.53E-04	4.16E-04	4.16E-04	--	1.48E-03
Total VOC	1.66	1.06	1.06	0.17	3.94
Total HAP	0.05	0.03	0.03	--	0.11

[1] Hourly Emission Rate (lb/hr) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) / Event duration (hr/event) x (1 lb-mol / 379.5 scf)

$$\text{Hourly Emission Rate (lb/hr)} = \frac{28.01\text{ lb}}{\text{lb-mol}} \left| \frac{1.035\ \%}{100} \right| \frac{157.00\text{ scf}}{\text{event}} \left| \frac{\text{event}}{1\text{ hr}} \right| \frac{1\text{ lb-mol}}{379.5\text{ scf}} = \frac{0.12\text{ lb}}{\text{hr}}$$

[2] Hourly Emission Rate (lb/hr) = Liquid Volume per Event (scf/event) x Liquid Density (lb/scf) / Event duration (hr/event)

$$\text{Hourly Emission Rate (lb/hr)} = \frac{0.0055\text{ scf}}{\text{event}} \left| \frac{31.64\text{ lb}}{\text{scf}} \right| \frac{\text{event}}{1\text{ hr}} = \frac{0.17\text{ lb}}{\text{hr}}$$

[3] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

Speciated Annual Emissions

Component	Annual Emissions (tpy)[1,2]				
	Meters	Pigging 12"	Pigging 16"	Truck Unloading Refrigerant Propane	Total
N_2	1.45E-03	2.01E-03	2.01E-03	--	5.46E-03
CO_2	8.72E-03	0.01	0.01	--	0.03
H_2S	--	--	--	--	0.00E+00
Methane	0.06	0.09	0.09	--	0.24
Ethane	0.01	0.02	0.02	--	0.06
Propane	9.96E-03	0.01	0.01	2.07E-03	0.04
i-Butane	1.43E-03	1.97E-03	1.97E-03	--	5.38E-03
n-Butane	3.55E-03	4.90E-03	4.90E-03	--	0.01
i-Pentane	1.19E-03	1.64E-03	1.64E-03	--	4.46E-03
n-Pentane	1.23E-03	1.70E-03	1.70E-03	--	4.64E-03
n-Hexane	5.05E-04	6.97E-04	6.97E-04	--	1.90E-03
Hexane +	7.77E-04	1.07E-03	1.07E-03	--	2.92E-03
Benzene	3.13E-05	4.32E-05	4.32E-05	--	1.18E-04
Cyclohexane	1.05E-04	1.46E-04	1.46E-04	--	3.97E-04
i-Heptane	5.78E-04	7.97E-04	7.97E-04	--	2.17E-03
n-Heptane	1.56E-04	2.15E-04	2.15E-04	--	5.85E-04
Toluene	3.69E-05	5.10E-05	5.10E-05	--	1.39E-04
i-Octane	2.18E-04	3.00E-04	3.00E-04	--	8.18E-04
n-Octane	2.86E-05	3.95E-05	3.95E-05	--	1.08E-04
Ethylbenzene	--	--	--	--	0.00E+00
m, n, p Xylene	1.06E-05	1.47E-05	1.47E-05	--	4.00E-05
i-Nonane	5.78E-05	7.98E-05	7.98E-05	--	2.17E-04
n-Nonane	6.43E-06	8.87E-06	8.87E-06	--	2.42E-05
i-Decane	7.13E-06	9.84E-06	9.84E-06	--	2.68E-05
n-Decane	--	--	--	--	0.00E+00
i-Undecanes	7.83E-06	1.08E-05	1.08E-05	--	2.95E-05
Total VOC	0.02	0.03	0.03	2.07E-03	0.08
Total HAP	5.84E-04	8.06E-04	8.06E-04	--	2.20E-03

[1] Annual Emission Rate (tpy) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) x (1 lb-mol / 379.5 scf) x Number of Events (events/yr) x (1 ton / 2,000 lb)

$$\text{Annual Emission Rate (tpy)} = \frac{28.01\ \text{lb}}{\text{lb-mol}} \times \frac{1.035\ \%}{100} \times \frac{157\text{scf}}{\text{event}} \times \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} \times \frac{24\ \text{events}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1.45\text{E-03 ton}}{\text{yr}}$$

[2] Annual Emission Rate for Propane Unloading (tpy) = Liquid Volume per Event (scf/event) x Liquid Density (lb/scf) x Number of Events (events/yr) x (1 ton / 2,000 lb)

$$\text{Annual Emission Rate (tpy)} = \frac{0.0055\ \text{scf}}{\text{event}} \times \frac{31.64\ \text{lb}}{\text{scf}} \times \frac{24\ \text{events}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{2.07\text{E-03 ton}}{\text{yr}}$$

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

MSS Activity Emissions Vented to Atmosphere - Greenhouse Gas

Global Warming Potentials [1]

CO_2	CH_4
1	21

Compound	Meters		Pigging 12"		Pigging 16"		Truck Unloading Refrigerant Propane		Total Fugitive Emissions	
	(lb/hr) [2, 3]	(tpy) [2]	(lb/hr) [2, 3]	(tpy) [2]	(lb/hr) [2, 3]	(tpy) [2]	(lb/hr) [2, 3]	(tpy) [2]	(lb/hr) [2, 3]	(tpy) [2]
CO_2	0.73	8.72E-03	0.46	0.01	0.46	0.01	--	--	1.65	0.03
CH_4	5.21	0.06	3.32	0.09	3.32	0.09	--	--	11.85	0.24
CO_2e	110.17	1.32	70.17	1.82	70.17	1.82	--	--	250.51	4.97

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[2] Hourly and annual emissions are obtained from the speciated tables and calculations performed in the tables above.

[3] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate for Meters (lb/hr) = $\frac{0.73\ \text{lb}}{\text{hr}} \times 1 + \frac{5.21\ \text{lb}}{\text{hr}} \times 21 = \frac{110.17\ \text{lb}}{\text{hr}}$

Site-wide Fugitive Components (EPN FUG-1)

Fugitive Component Emissions

Fugitives Counts and VOC Content

Stream	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors	O_2 Sensors	Gas Chromatographs	VOC Content (Weight %)
Inlet Gas	650	2	5,200	12	--	--	1,247	4	1	18.52
Residue Gas	1,242	2	660	5	43	--	3,019	2	1	0.11
Light Oil	211	2	1,688	--	--	--	173	--	--	99.96

LDAR Control [1] (%)

Stream	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors
Gas/Vapor	97	0	30	85	97	97	30
Light Liquid	97	85	30	--	--	97	30

[1] Control efficiency for each type of component for 28 VHP Leak Detection and Repair Program (LDAR).

Oil and Gas Production Operations Emission Factors

Stream	Emission Factor [1] (lb/hr)/component							Emission Factor [2] (scf/hr)	
	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors	O_2 Sensors	Gas Chromatographs
Gas	0.00992	0.00529	0.00086	0.0194	0.0194	0.00441	0.00044	1.5	1.5
Light Oil	0.0055	0.02866	0.000243	0.0165	0.0165	0.00309	0.000463	--	--

[1] Oil and Gas Production emission factors obtained from TCEQ, Industrial Emissions Assessment Section, Emissions Factors for Equipment Leak Fugitive Components, RG-360, January 2005.

[2] Emission factors for the O_2 sensors and gas chromatographs were provided by Targa.

Site-wide Fugitive Components (EPN FUG-1)

Stream Speciation

Component	MW (lb/lb-mol)	Stream Mole Percent (%)			Stream Weight Percent (%)		
		Inlet Gas [1]	Residue Gas [2]	Light Oil [3]	Inlet Gas [1]	Residue Gas [2]	Light Oil [3]
N_2	28.01	1.035	1.750	--	1.353	2.996	--
CO_2	44.01	3.952	0.010	0.00E+00	8.118	0.027	0.00E+00
H_2S	34.08	--	--	--	--	--	--
Methane	16.04	77.776	97.500	0.010	58.237	95.583	0.00E+00
Ethane	30.07	9.811	0.700	0.137	13.769	1.286	0.040
Propane	44.10	4.508	0.040	1.300	9.278	0.108	0.590
i-Butane	58.12	0.491	--	0.819	1.332	--	0.490
n-Butane	58.12	1.219	--	3.515	3.307	--	2.090
i-Pentane	72.15	0.328	--	3.499	1.105	--	2.580
n-Pentane	72.15	0.341	--	5.355	1.148	--	3.950
n-Hexane	86.18	0.117	--	--	0.471	--	--
Hexanes	86.18	0.180	--	12.261	0.724	--	10.847
Benzene	78.11	0.008	--	0.633	0.029	--	0.503
Cyclohexane	84.16	0.025	--	--	0.098	--	--
i-Heptane	100.21	0.115	--	--	0.538	--	--
n-Heptane	100.21	0.031	--	25.609	0.145	--	24.990
Toluene	92.14	0.008	--	3.871	0.034	--	3.643
i-Octane	114.23	0.038	--	--	0.203	--	--
n-Octane	114.23	0.005	--	27.425	0.027	--	30.084
Ethylbenzene	106.17	--	--	0.085	--	--	0.093
m, o, p Xylene	106.16	0.002	--	2.217	0.010	--	2.409
i-Nonane	128.20	0.009	--	--	0.054	--	--
n-Nonane	128.20	0.001	--	9.355	0.006	--	11.663
i-Decane	142.29	0.001	--	--	0.007	--	--
n-Decane	142.29	--	--	3.910	--	--	6.029
i-Undecanes	156.31	0.001	--	--	0.007	--	--
Total VOC		7.43	0.04	99.85	18.52	0.11	99.96

[1] Inlet gas composition is calculated from the combination of the New Harp and Waggoner gas streams that will be entering the Longhorn Plant. Provided by Targa to Trinity via email on 12/02/11.

[2] Residue gas composition is obtained from a similar Targa facility.

[3] Light oil composition is obtained from a similar Targa facility.

Site-wide Fugitive Components (EPN FUG-1)

Speciated Hourly Emissions

Component	Hourly Emissions (lb/hr) [1, 2]							
	Inlet Gas			Residue Gas			Light Oil	Total
	Traditional Components	O_2 Sensors	Gas Chromatographs	Traditional Components	O_2 Sensors	Gas Chromatographs		
CO_2	0.30	0.03	6.87E-03	4.70E-04	3.48E-05	1.74E-05	0.00E+00	0.34
Methane	2.19	0.20	0.05	1.67	0.12	0.06	0.00E+00	4.29
Ethane	0.52	0.05	0.01	0.02	1.66E-03	8.32E-04	1.55E-04	0.60
Propane	0.35	0.03	7.86E-03	1.88E-03	1.39E-04	6.97E-05	2.28E-03	0.39
i-Butane	0.05	4.51E-03	1.13E-03	--	--	--	1.89E-03	0.06
n-Butane	0.12	0.01	2.80E-03	--	--	--	8.08E-03	0.15
i-Pentane	0.04	3.74E-03	9.35E-04	--	--	--	9.97E-03	0.06
n-Pentane	0.04	3.89E-03	9.72E-04	--	--	--	0.02	0.06
n-Hexane	0.02	1.59E-03	3.99E-04	--	--	--	--	0.02
Hexane +	0.03	2.45E-03	6.13E-04	--	--	--	0.04	0.07
Benzene	1.09E-03	9.88E-05	2.47E-05	--	--	--	1.95E-03	3.16E-03
Cyclohexane	3.69E-03	3.33E-04	8.32E-05	--	--	--	--	4.10E-03
i-Heptane	0.02	1.82E-03	4.56E-04	--	--	--	--	0.02
n-Heptane	5.44E-03	4.91E-04	1.23E-04	--	--	--	0.10	0.10
Toluene	1.29E-03	1.17E-04	2.91E-05	--	--	--	0.01	0.02
i-Octane	7.60E-03	6.86E-04	1.72E-04	--	--	--	--	8.46E-03
n-Octane	1.00E-03	9.03E-05	2.26E-05	--	--	--	0.12	0.12
Ethylbenzene	--	--	--	--	--	--	3.60E-04	3.60E-04
m, o, p Xylene	3.72E-04	3.36E-05	8.39E-06	--	--	--	9.31E-03	9.73E-03
i-Nonane	2.02E-03	1.82E-04	4.56E-05	--	--	--	--	2.25E-03
n-Nonane	2.25E-04	2.03E-05	5.07E-06	--	--	--	0.05	0.05
i-Decane	2.49E-04	2.25E-05	5.62E-06	--	--	--	--	2.77E-04
n-Decane	--	--	--	--	--	--	0.02	0.02
i-Undecanes	2.74E-04	2.47E-05	6.18E-06	--	--	--	--	3.05E-04
Total VOC	0.70	0.06	0.02	1.88E-03	1.39E-04	6.97E-05	0.39	1.16
Total HAP	0.02	1.84E-03	4.61E-04	--	--	--	0.03	0.05

[1] Speciated Hourly Emissions for Traditional Components (lb/hr) =
Sum of each [Component Count x Emission Factor [(lb/hr)/ component] x Compound Content (wt %) / 100 x (1-28 VHP Control (%) / 100)]

[2] Hourly Emission Rate for O_2 Sensors and Gas Chromatographs (lb/hr) = MW (lb/lb-mol) x Composition (mol %) x Emission Factor (scf/hr) x (1 lb-mol / 379.5 scf) x No. of Components

Propane Speciated Hourly Emission Rate (lb/hr) =

$$\frac{44.10\ \text{lb}}{\text{lb-mol}} \;\Big|\; \frac{4.508\ \%}{100} \;\Big|\; \frac{1.50\ \text{scf}}{\text{hr}} \;\Big|\; \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} \;\Big|\; 4 \quad = \quad \frac{0.03\ \text{lb}}{\text{hr}}$$

Site-wide Fugitive Components (EPN FUG-1)

Speciated Annual Emissions

Component	Annual Emissions (tpy) [1]							
	Inlet Gas			Residue Gas			Light Oil	Total
	Traditional Components	O_2 Sensors	Gas Chromatographs	Traditional Components	O_2 Sensors	Gas Chromatographs		
CO_2	1.33	0.12	0.03	2.06E-03	1.52E-04	7.62E-05	0.00E+00	1.49
Methane	9.57	0.86	0.22	7.31	0.54	0.27	0.00E+00	18.78
Ethane	2.26	0.20	0.05	0.10	7.29E-03	3.64E-03	6.77E-04	2.63
Propane	1.53	0.14	0.03	8.25E-03	6.11E-04	3.05E-04	9.99E-03	1.72
i-Butane	0.22	0.02	4.94E-03	--	--	--	8.30E-03	0.25
n-Butane	0.54	0.05	0.01	--	--	--	0.04	0.64
i-Pentane	0.18	0.02	4.10E-03	--	--	--	0.04	0.25
n-Pentane	0.19	0.02	4.26E-03	--	--	--	0.07	0.28
n-Hexane	0.08	6.98E-03	1.75E-03	--	--	--	--	0.09
Hexane +	0.12	0.01	2.69E-03	--	--	--	0.18	0.32
Benzene	4.79E-03	4.33E-04	1.08E-04	--	--	--	8.52E-03	0.01
Cyclohexane	0.02	1.46E-03	3.64E-04	--	--	--	--	0.02
i-Heptane	0.09	7.98E-03	2.00E-03	--	--	--	--	0.10
n-Heptane	0.02	2.15E-03	5.38E-04	--	--	--	0.42	0.45
Toluene	5.66E-03	5.10E-04	1.28E-04	--	--	--	0.06	0.07
i-Octane	0.03	3.01E-03	7.51E-04	--	--	--	--	0.04
n-Octane	4.38E-03	3.96E-04	9.89E-05	--	--	--	0.51	0.51
Ethylbenzene	--	--	--	--	--	--	1.58E-03	1.58E-03
m, o, p Xylene	1.63E-03	1.47E-04	3.68E-05	--	--	--	0.04	0.04
i-Nonane	8.85E-03	7.99E-04	2.00E-04	--	--	--	--	9.85E-03
n-Nonane	9.84E-04	8.88E-05	2.22E-05	--	--	--	0.20	0.20
i-Decane	1.09E-03	9.85E-05	2.46E-05	--	--	--	--	1.21E-03
n-Decane	--	--	--	--	--	--	0.10	0.10
i-Undecanes	1.20E-03	1.08E-04	2.71E-05	--	--	--	--	1.33E-03
Total VOC	3.05	0.27	0.07	8.25E-03	6.11E-04	3.05E-04	1.69	5.09
Total HAP	0.09	8.07E-03	2.02E-03	--	--	--	0.11	0.21

[1] Speciated Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x (1 ton / 2,000 lb)

$$\text{Propane Speciated Annual Emissions (tpy)} = \frac{0.35\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 1.53\ \text{tpy}$$

Site-wide Fugitive Components (EPN FUG-1)

Fugitive Component Emissions - Greenhouse Gas

Global Warming Potentials [1]

CO_2	CH_4
1	21

Compound	Total Fugitive Emissions	
	(lb/hr) [2]	(tpy) [3]
CO_2	0.34	1.49
CH_4	4.29	18.78
CO_2e	90.38	395.86

[1] Global warming potentials (GWP) obtained from 40 CFR 98 Subpart A Table A-1.

[2] CO_2e emissions based on GWPs for each greenhouse gas pollutant.

CO_2e Hourly Emission Rate (lb/hr) = CO_2 Emission Rate (lb/hr) x CO_2 GWP + CH_4 Emission Rate (lb/hr) x CH_4 GWP

Example CO_2e Hourly Emission Rate (lb/hr) = $\frac{0.34\ \text{lb}}{\text{hr}} \times 1 + \frac{4.29\ \text{lb}}{\text{hr}} \times 21 = \frac{90.38\ \text{lb}}{\text{hr}}$

[3] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x 8,760 (hr/yr) x (1 ton / 2,000 lb)

Example CO_2e Annual Emission Rate (tpy) = $\frac{90.38\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}}$ = 395.86 tpy

8. EMISSION POINT SUMMARY (TCEQ TABLE 1(A))

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**February 2012**	Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Targa Gas Processing LLC - Longhorn Gas Plant**			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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
1	1	TEG-1 Glycol Reboiler	CO_2	233.78	1,023.96
			CH_4	<0.01	0.02
			N_2O	<0.01	<0.01
			CO_2e	234.00	1,024.92
2	2	TEG Dehydrator During RTO Downtime	CO_2	0.02	<0.01
			CH_4	3.13	0.24
			CO_2e	65.81	5.00
3	3	HTR-1 Regen Heater	CO_2	1,449.44	6,348.55
			CH_4	0.03	0.13
			N_2O	<0.01	0.01
			CO_2e	1,450.91	6,354.99
4	4	HTR-2 Hot Oil Heater	CO_2	11,455.22	50,173.86
			CH_4	0.22	0.94
			N_2O	0.02	0.09
			CO_2e	11,466.44	50,223.01
5	2, 15	RTO-1 Regen Thermal Oxidizer	CO_2	26,522.86	116,170.13
			CH_4	0.29	1.27
			N_2O	0.07	0.31
			CO_2e	26,550.65	116,291.83
6	6	Flare-1 Flare (Pilot)	CO_2	17.53	76.80
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	17.55	76.87

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
15	15	Amine Still Vent During RTO Downtime	CO_2	26,131.43	1,985.99
			CH_4	25.97	1.97
			CO_2e	26,676.83	2,027.44
FUG-1	FUG-1	Plant-wide Fugitive Components	CO_2	0.34	1.49
			CH_4	4.29	18.78
			CO_2e	90.38	395.86
5-MSS	5-MSS	RTO-1 Startup	CO_2	350.67	1.40
			CH_4	<0.01	<0.01
			N_2O	<0.01	<0.01
			CO_2e	351.01	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	CO_2	1631.17	9.85
			CH_4	0.06	<0.01
			N_2O	<0.01	<0.01
			CO_2e	1635.26	9.87
7-MSS	7-MSS	PR-1 16" Reciever	CO_2	0.46	0.01
			CH_4	3.32	0.09
			CO_2e	70.17	1.82
8-MSS	8-MSS	PR-2 12" Reciever	CO_2	0.46	0.01
			CH_4	3.32	0.09
			CO_2e	70.17	1.82
FUG-MSS [1]	FUG-MSS	Plant-wide MSS Fugitives	CO_2	0.73	<0.01
			CH_4	5.21	0.06
			CO_2e	110.17	1.32

[1] FUG-MSS does not include pigging since those activities have separate EPNs.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**February 2012**	Permit No.:	**TBD**
Regulated Entity No.	**TBD**		
Area Name:	**Targa Gas Processing LLC - Longhorn Gas Plant**	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 Height (Feet)	6. Height Above Ground (Feet)	7.Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)			Diameter (Feet) (A)	Velocity (fps) (B)	Temperature (°f) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
1	1	TEG-1 Glycol Reboiler	14	637,172	3,686,875		16.67	1.33	7.94	750			
2	2	TEG Dehydrator During RTO Downtime	14	637,123	3,686,838		20	0.50	30.15	210.70			
3	3	HTR-1 Regen Heater	14	637,180	3,686,874		18.00	2.50	6.45	680			
4	4	HTR-2 Hot Oil Heater	14	637,190	3,686,867		124.00	6.75	13.89	550			
5	2, 15	RTO-1 Regen Thermal Oxidizer	14	637,194	3,686,857		30.00	3.5	51.97	600			
6	6	Flare-1 Flare (Pilot)	14	637,303	3,686,904		75.00	1.67	TBD	1,000			
11	11	MEOH-1 Methanol Storage	14	637,085	3,686,958		4.00	0.003	0.003	Ambient			
15	15	Amine Still Vent During RTO Downtime	14	637,090	3,686,869		75	1.00	80.30	120			
16	16	Produced Water Tank 210 bbl	14	637,360	3,686,790		15	0.003	0.003	Ambient			
17	17	LP Condensate Tank 1 (During VRU Downtime)	14	637,363	3,686,793		15	0.003	0.003	Ambient			
18	18	LP Condensate Tank 2 (During VRU Downtime)	14	637,366	3,686,797		15	0.003	0.003	Ambient			
21	21	Open Drain Sump	14	637,133	3,686,789		1	0.003	0.003	Ambient			
FUG-1	FUG-1	Plant-wide Fugitive Components	14	637,138	3,686,826		10				1,090	1,043	
FUG-2	FUG-2	Truck Loading	14	637,355	3,686,802		3				50	50	
5-MSS	5-MSS	RTO-1 Startup	14	637,194	3,686,857		30.00	3.50	TBD	TBD			
6-MSS	6-MSS	Flare-1 Flare MSS	14	637,303	3,686,904		75.00	1.67	TBD	1,000			
7-MSS	7-MSS	PR-1 16" Reciever	14	637,007	3,686,726		TBD				TBD	TBD	TBD
8-MSS	8-MSS	PR-2 12" Reciever	14	637,010	3,686,723		TBD				TBD	TBD	TBD
20-MSS	20-MSS	Refrigerant Unloading	14	637,161	3,686,969		TBD				TBD	TBD	TBD
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	14	637,138	3,686,826		10				1,090	1,043	

9. FEDERAL REGULATORY REQUIREMENTS

This section addresses the applicability of the following parts of 40 CFR for the equipment at the proposed Longhorn Gas Plant:

> Nonattainment New Source Review
> Prevention of Significant Deterioration

All applicable state and federal requirements (e.g., New Source Performance Standards and National Emission Standards for Hazardous Air Pollutants), with the exception to those pertaining to GHG emissions, are addressed in the TCEQ minor source state NSR permit application. The TCEQ application is included in Appendix G as reference.

9.1. NNSR APPLICABILITY REVIEW

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[12] In a letter dated December 9, 2011, the U.S. EPA expressed its intent to designate Wise County as nonattainment for the eight-hour ozone standard and include the county in the existing DFW ozone nonattainment area.[13] In the event of a redesignation of Wise County to nonattainment, the proposed Longhorn Gas Plant may be potentially subject to NNSR requirements for NO_x and VOC.

DFW is currently classified as a serious ozone nonattainment area for the eight-hour ozone standard.[14] It is anticipated that if Wise County is designated as nonattainment for the eight-hour ozone standard, the classification for the county will also be serious. In a serious nonattainment ozone county, NNSR major source thresholds are 50 tpy for NO_x and VOC, each. As shown in the table included at the end of this section, the proposed NO_x and VOC emissions from the Longhorn Gas Plant will be less than 50 tpy, each. Therefore, the proposed Longhorn Gas Plant would not be considered a major source for ozone precursors under the proposed nonattainment designation, and NNSR permitting requirements will not apply to the proposed facility even if Wise County is redesignated a serious ozone nonattainment area under the eight-hour standard.

9.2. PSD APPLICABILITY REVIEW

The proposed Longhorn Gas Plant will be a new major source with respect to GHG emissions and subject to PSD permitting requirements under the GHG Tailoring Rule because emissions of CO_2e will be greater than 100,000 tpy.

The proposed facility will be located in Wise County, Texas, which is currently classified as attainment/unclassified for all criteria pollutants.[15] PSD permitting requirements apply to any new major stationary source located in areas designated as attainment/unclassified. Since the proposed Longhorn Gas Plant will be a major source for GHG emissions, EPA requires non-GHG emissions to be compared to the significant emission rates (SER) in accordance with EPA's longstanding "major for one, major for all" PSD policy to determine PSD applicability.[16]

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[12] Per 40 CFR §81.344 (Effective April 5, 2005).

[13] Letter from Dr. Al Armendariz, U.S. EPA Region 6 Administrator, to Texas Governor Rick Perry, dated December 9, 2011.

[14] Per 40 CFR §81.344 (Effective January 19, 2011).

[15] Per 40 CFR §81.344 (Effective April 5, 2005).

[16] Triggering PSD at Non-Anyway Sources and Modifications, EPA Q&A Document, dated March 15, 2011. http://www.epa.gov/nsr/ghgdocs/TriggeringPSDatnonAnywaySourcesandMods.pdf.

As shown in the table included at the end of this section, emissions for all non-GHG pollutants are less than both major source thresholds and their respective SER. Therefore, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG emissions and the facility is subject to the jurisdiction of the TCEQ for such emissions.

Accordingly, Targa is submitting applications to both agencies to obtain the requisite authorizations to construct. The minor source state NSR permit application submitted to TCEQ is included in Appendix G of this GHG PSD permit application for reference.

Site-Wide Emission Summary for PSD Applicability

Fugitive emissions are not included in calculculations per 30 TAC § 122.10(13)(C).

Normal Operations Summary

EPN	FIN	Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
1	1	TEG-1 Glycol Reboiler	0.96	0.53	0.04	0.04	0.04	0.04	0.00	1,024.92
2	2	TEG Dehydrator During RTO Downtime	--	--	4.15	--	--	--	--	5.00
3	3	HTR-1 Regen Heater	5.43	4.03	7.62	0.39	0.39	0.39	0.04	6,354.99
4	4	HTR-2 Hot Oil Heater	21.46	31.76	2.28	3.15	3.15	3.15	0.25	50,223.01
5	2, 15	RTO-1 Regen Thermal Oxidizer	0.48	14.55	3.21	--	--	--	13.16	116,291.83
6	6	Flare-1 Flare (Pilot)	0.09	0.18	6.09E-04	--	--	--	3.46E-03	76.87
11	11	MEOH-1 Methanol Storage	--	--	0.06	--	--	--	--	--
15	15	Amine Still Vent During RTO Downtime	--	--	1.41	--	--	--	--	2,027.44
16	16	Produced Water Tank 210 bbl	--	--	1.12	--	--	--	--	--
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	0.02	--	--	--	--	--
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	0.02	--	--	--	--	--
21	21	Open Drain Sump	--	--	0.01	--	--	--	--	--
		Total Normal Operations Emissions	**28.42**	**51.05**	**19.92**	**3.58**	**3.58**	**3.58**	**13.45**	**176,004.06**

MSS Operations Summary

EPN	FIN	Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
5-MSS	5-MSS	RTO-1 Startup	1.80E-03	1.80E-03	6.34E-05	--	--	--	6.92E-06	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	6.07E-03	1.21E-02	2.95E-01	--	--	--	4.74E-05	9.87
		Total MSS Emissions	**7.87E-03**	**1.39E-02**	**2.95E-01**	**0.00**	**0.00**	**0.00**	**5.43E-05**	**11.28**

Total Operations Summary

		Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
		Normal Operations	28.42	51.05	19.92	3.58	3.58	3.58	13.45	176,004.06
		MSS Activities	7.87E-03	1.39E-02	2.95E-01	0.00	0.00	0.00	5.43E-05	11.28
		Total Site-wide Emissions	**28.43**	**51.06**	**20.22**	**3.58**	**3.58**	**3.58**	**13.45**	**176,015.34**

Comparison to PSD Limits [1]

Prevention of Significant Deterioration (PSD) Major Source Threshold	250	250	250	250	250	250	250	100,000
Is the site above PSD major source threshold?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**YES**
Significant Emission Rates (SER)	40	100	40	--	15	10	40	--
Is the site above SERs?	**NO**	**NO**	**NO**	**--**	**NO**	**NO**	**NO**	**--**

[1] According to EPA guidance, the "major for one, major for all" PSD policy applies to GHGs for any project occurring on or after July 1, 2011. Therefore, if a site is a major source of GHGs, then the criteria pollutant emissions must be compared to the Significant Emission Rates to determine PSD applicability.

Comparison to NNSR Limits [1]

Nonattainment New Source Review (NNSR) Limits	50	--	50	--	--	--	--	--
Is the site above NNSR limits?	**NO**	**--**	**NO**	**--**	**--**	**--**	**--**	**--**

[1] Wise County is currently classified as an attainment/unclassified area for all criteria pollutants. In a letter dated December 9, 2011, the U.S. EPA expressed their intent to designate Wise County as nonattainment for the eight-hour ozone standard, including the county in the existing Dallas-Fort Worth serious ozone nonattainment area. In the event of a redesignation of Wise County to nonattainment, the proposed Longhorn Gas Plant would be potentially subject to NNSR requirements for NO_X and VOC.

10. GHG BEST AVAILABLE CONTROL TECHNOLOGY

This section discusses the approach used in completing the GHG BACT analysis, as well as documenting the emission units for which the GHG BACT analyses were performed.

10.1. BACT DEFINITION

The requirement to conduct a BACT analysis is set forth in the PSD regulations 40 CFR §52.21(j)(2):

(j) Control Technology Review.

(2) A new major stationary source shall apply best available control technology for each regulated NSR pollutant that it would have the potential to emit in significant amounts.

BACT is defined in the PSD regulations 40 CFR §52.21(b)(12)(emphasis added) in relevant part as:

…<u>an emissions limitation</u> (including a visible emission standard) based on the maximum degree of reduction for <u>each pollutant</u> subject to regulation under Act which would be emitted from any <u>proposed major stationary source</u> or major modification which the Administrator, on a <u>case-by-case basis</u>, taking into account energy, environmental, and economic impacts and other costs, determines is <u>achievable</u> for such source or modification through application of <u>production processes</u> or <u>available</u> methods, systems, and techniques, including fuel cleaning or treatment or innovative fuel combustion techniques for control of such pollutant. In no event shall application of best available control technology result in emissions of any pollutant which would <u>exceed the emissions allowed by any applicable standard under 40 CFR parts 60 and 61</u>.

Although this definition was not changed by the Tailoring Rule, differences in the characteristics of criteria pollutant and GHG emissions from large industrial sources present several GHG-specific considerations under the BACT definition which warrant further discussion. Those underlined terms in the BACT definition are addressed further below.

10.1.1. Emission Limitation

BACT is "an emission limitation," not an emission reduction rate or a specific technology. While BACT is prefaced upon the application of technologies reflecting the maximum reduction rate achievable, the final result of BACT is an emission limit. Typically, when quantifiable and measurable, this limit would be expressed as an emission rate limit of a pollutant (e.g., lb/MMBtu, ppm, or lb/hr). [17, 18] Furthermore, EPA's guidance on GHG BACT has indicated that GHG BACT limitations should be averaged over long-term timeframes such as a 30- or 365-day rolling average.[19]

10.1.2. Each Pollutant

Since BACT applies to "each pollutant subject to regulation under the Act", the BACT evaluation process is typically conducted for each regulated NSR pollutant individually and not for a combination of pollutants.[20] For PSD applicability assessments involving GHGs, the regulated NSR pollutant subject to regulation under the Clean Air Act

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[17] The definition of BACT allows use of a work practice where emissions are not easily measured or enforceable. 40 CFR §52.21(b)(12).

[18] Emission limits can be broadly differentiated as "rate-based" or "mass-based." For a turbine, a rate-based limit would typically be in units of lb/MMBtu (mass emissions per heat input). In contrast, a typical mass-based limit would be in units of lb/hr (mass emissions per time).

[19] *PSD and Title V permitting Guidance for Greenhouse Gases.* March 2011, page 46.

[20] 40 CFR §52.21(b)(12)

(CAA) is the sum of six greenhouse gases and not a single pollutant. In the final Tailoring Rule preamble, EPA went beyond applying this combined pollutant approach for GHGs to PSD applicability and made the following recommendations that suggest applicants should conduct a single GHG BACT evaluation on a CO_2e basis for emission sources that emit more than one GHG pollutant:

> *However, we disagree with the commenter's ultimate conclusion that BACT will be required for each constituent gas rather than for the regulated pollutant, which is defined as the combination of the six well-mixed GHGs. To the contrary, we believe that, in combination with the sum-of-six gases approach described above, the use of the CO_2e metric will enable the implementation of flexible approaches to design and implement mitigation and control strategies that look across all six of the constituent gases comprising the air pollutant (e.g., flexibility to account for the benefits of certain CH_4 control options, even though those options may increase CO_2). Moreover, we believe that the CO_2e metric is the best way to achieve this goal because it allows for tradeoffs among the constituent gases to be evaluated using a common currency.*[21]

Targa acknowledges the potential benefits of conducting a single GHG BACT evaluation on a CO_2e basis for the purposes of addressing potential tradeoffs among constituent gases for certain types of emission units. However, for the proposed Longhorn Gas Plant, the GHG emissions are driven primarily by CO_2. CO_2 emissions represent more than 99% of the total CO_2e for the project as a whole. As such, the following top-down GHG BACT analysis should and will focus on CO_2.

10.1.3. BACT Applies to the Proposed Source

BACT applies to the type of source proposed by the applicant. BACT does not redefine the source. The applicant defines the source (i.e., its goals, aims and objectives). Although BACT is based on the type of source as proposed by the applicant, the scope of the applicant's ability to define the source is not absolute. A key task for the reviewing agency is to determine which parts of the proposed process are inherent to the applicant's purpose and which parts may be changed without changing that purpose. Targa has provided substantial project discussion in Section 6 of this report to aid the technical reviewers in need and scope of this project and how GHG BACT should be reviewed in light of this detailed information.

10.1.4. Case-by-Case Basis

Unlike many of the CAA programs, the PSD program's BACT evaluation is case-by-case. BACT permit limits are not simply the requirement for a control technology because of its application elsewhere or the direct transference of the lowest emission rate found in other permits for similar sources, applied to the proposed source. EPA has explained how the top-down BACT analysis process works on a case-by-case basis.

> *In brief, the top-down process provides that all available control technologies be ranked in descending order of control effectiveness. The PSD applicant first examines the most stringent--or "top"--alternative. That alternative is established as BACT unless the applicant demonstrates, and the permitting authority in its informed judgment agrees, that technical considerations, or energy, environmental, or economic impacts justify a conclusion that the most stringent technology is not "achievable" in that case. If the most stringent technology is eliminated in this fashion, then the next most stringent alternative is considered, and so on.*[22]

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[21] 75 FR 31,531, *Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule; Final Rule*, June 3, 2010.

[22] Draft NSR Manual at B-2. "The NSR Manual has been used as a guidance document in conjunction with new source review workshops and training, and as a guide for state and federal permitting officials with respect to PSD requirements and policy. Although it is not binding Agency regulation, the NSR Manual has been looked to by this Board as a statement of the Agency's thinking on certain PSD issues. E.g., *In re RockGen*

To assist applicants and regulators with the case-by-case process, in 1990 EPA issued a Draft Manual on New Source Review permitting which included a "top-down" BACT analysis.

The five steps in a top-down BACT evaluation can be summarized as follows:

- Step 1. Identify all available control technologies;
- Step 2. Eliminate technically infeasible options;
- Step 3. Rank the technically feasible control technologies by control effectiveness;
- Step 4. Evaluate most effective controls; and
- Step 5. Select BACT.

While this EPA-recommended five step process can be directly applied to GHGs without any significant modifications, it is important to note that the top-down process is conducted on a unit-by-unit, pollutant-by-pollutant basis and only considers the portions of the facility that are considered "emission units" as defined under the PSD regulations.[23]

10.1.5. Achievable

BACT is to be set at the lowest value that is "achievable." However, there is an important distinction between emission rates achieved at a specific time on a specific unit, and an emission limitation that a unit must be able to meet continuously over its operating life. As discussed by the DC Circuit Court of Appeals:

> *In National Lime Ass'n v. EPA, 627 F.2d 416, 431 n.46 (D.C. Cir. 1980), we said that where a statute requires that a standard be "achievable," it must be achievable "under most adverse circumstances which can reasonably be expected to recur."* [24]

EPA has reached similar conclusions in prior determinations for PSD permits.

> *Agency guidance and our prior decisions recognize a distinction between, on the one hand, measured 'emissions rates,' which are necessarily data obtained from a particular facility at a specific time, and on the other hand, the 'emissions limitation' determined to be BACT and set forth in the permit, which the facility is required to continuously meet throughout the facility's life. Stated simply, if there is uncontrollable fluctuation or variability in the measured emission rate, then the lowest measured emission rate will necessarily be more stringent than the "emissions limitation" that is "achievable" for that pollution control method over the life of the facility. Accordingly, because the "emissions limitation" is applicable for the facility's life, it is wholly appropriate for the permit issuer to consider, as part of the BACT analysis, the extent to which the available data demonstrate whether the emissions rate at issue has been achieved by other facilities over a long term.*[25]

Thus, BACT must be set at the lowest feasible emission rate recognizing that the facility must be in compliance with that limit for the lifetime of the facility on a continuous basis. While viewing individual unit performance can be

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Energy Ctr., 8 E.A.D. 536, 542 n. 10 (EAB 1999), *In re Knauf Fiber Glass, GmbH*, 8 E.A.D. 121, 129 n. 13 (EAB 1999)." *In re Prairie State Generating Company* 13 E.A.D. 1, 13 n 2 (2006)

23 Pursuant to 40 CFR §52.21(a)(7), emission unit means any part of a stationary source that emits or would have the potential to emit any regulated NSR pollutant.

24 As quoted in Sierra Club v. U.S. EPA (97-1686).

25 U.S. EPA Environmental Appeals Board decision, *In re: Newmont Nevada Energy Investment L.L.C.* PSD Appeal No. 05-04, decided December 21, 2005. Environmental Administrative Decisions, Volume 12, Page 442.

instructive in evaluating what BACT might be, any actual performance data must be viewed carefully, as rarely will the data be adequate to truly assess the performance that a unit will achieve during its entire operating life.

To assist in meeting the BACT limit, the source must consider production processes or available methods, systems or techniques, as long as those considerations do not redefine the source.

10.1.6. Production Process

The definition of BACT lists both production processes and control technologies as possible means for reducing emissions.

10.1.7. Available

The term "available" in the definition of BACT is implemented through a feasibility analysis – a determination that the technology being evaluated is demonstrated or available and applicable.

10.1.8. Floor

For criteria pollutants, the least stringent emission rate allowable for BACT is any applicable limit under either New Source Performance Standards (NSPS – Part 60) or National Emission Standards for Hazardous Air Pollutants (NESHAP – Parts 61). Since no GHG limits have been incorporated into any existing NSPS or Part 61 NESHAPs, no floor for a GHG BACT analysis is available for consideration.

10.2. GHG BACT ASSESSMENT METHODOLOGY

GHG BACT for the proposed project has been evaluated via a "top-down" approach which includes the steps outlined in the following subsections.

It should be noted that the scope of a BACT review was clarified in two ways with respect to GHGs:

- EPA stressed that applicants should clearly define the scope of the project being reviewed. Targa has provided this information in Section 6 of this application.[26]
- EPA clarified that the scope of the BACT should focus on the project's largest contributors to CO_2e and may subject less significant contributors for CO_2e to less stringent BACT review. Because the project's GHG emissions are dominated by the amine treater via the RTO (and more specifically direct CO_2 emissions) and process heaters, this BACT analysis focuses mainly on these predominant sources of CO_2e from the project. GHG emissions from small emission sources such as storage tanks are not included in the BACT analysis.

10.2.1. Step 1 - Identify All Available Control Technologies

Available control technologies for CO_2e with the practical potential for application to the emission unit are identified. The application of demonstrated control technologies in other similar source categories to the emission unit in question can also be considered. While identified technologies may be eliminated in subsequent steps in the analysis based on technical and economic infeasibility or environmental, energy, economic or other impacts, control technologies with potential application to the emission unit under review are identified in this step.

[26] *PSD and Title V permitting Guidance for Greenhouse Gases.* March 2011, pages 22-23.

Under Step 1 of a criteria pollutant BACT analysis, the following resources are typically consulted when identifying potential technologies:

- EPA's Reasonably Available Control Technology (RACT)/Best Available Control Technology (BACT)/Lowest Achievable Emission Reduction (LAER) Clearinghouse (RBLC) database;
- Determinations of BACT by regulatory agencies for other similar sources or air permits and permit files from federal or state agencies;
- Engineering experience with similar control applications;
- Information provided by air pollution control equipment vendors with significant market share in the industry; and/or
- Review of literature from industrial technical or trade organizations.

However, since GHG BACT is a new requirement, the RBLC database search did not result in any records for GHGs at oil and gas or natural gas processing industries. Primarily, Targa will rely on items (2) through (5) listed above and information from the EPA BACT GHG Work Group for data to establish BACT.

EPA's "top-down" BACT analysis procedure also recommends the consideration of inherently lower emitting processes as available control options under Step 1. For GHG BACT analyses, low-carbon intensity fuel selection is the primary control option that can be considered a lower emitting process. As a natural gas processing plant, Targa proposes the use of pipeline quality natural gas only for all on-site combustion equipment. Table C-1 of 40 CFR Part 98 shows CO_2 emissions per unit heat input (MMBtu) for a wide variety of industrial fuel types. Only biogas (captured methane) and coke oven gas result in lower CO_2 emissions per unit heat input than natural gas.

Additionally, EPA's GHG BACT guidance suggests that carbon capture and sequestration (CCS) be evaluated as an available control for substantial, large projects such as steel mills, refineries, and cement plants where $_{CO2e}$ emissions levels are in the order of 1,000,000 tpy CO_2e, or for industrial facilities with high-purity CO_2 streams.[27] However, EPA explained that "[t]his does not mean CCS should be selected as BACT for such sources." The proposed Longhorn Gas Plant emissions are approximately 177,536 tpy CO_2e (including emissions from MSS activities). Only the amine treater (used to remove CO_2 from the inlet gas) results in a concentrated CO_2 stream with sulfur compound impurities. All other emission sources result in low purity CO_2 streams. Nonetheless, CCS is evaluated as a control option for the proposed project.

10.2.2. Step 2 - Eliminate Technically Infeasible Options

After the available control technologies have been identified, each technology is evaluated with respect to its technical feasibility in controlling GHG emissions from the source in question. The first question in determining whether or not a technology is feasible is whether or not it is demonstrated. If so, it is deemed feasible. Whether or not a control technology is demonstrated is considered to be a relatively straightforward determination.

> Demonstrated "means that it has been installed and operated successfully elsewhere on a similar facility." *Prairie State*, slip op. at 45. "This step should be straightforward for control technologies that are demonstrated--if the control technology has been installed and operated successfully on the type of source under review, it is demonstrated and it is technically feasible."[28]

[27] General GHG Permitting Guidance at 42-43.

[28] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.17.

An undemonstrated technology is only technically feasible if it is "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".[29] Control technologies in the R&D and pilot scale phases are not considered available. Based on EPA guidance, an available control technology is presumed to be applicable if it has been permitted or actually implemented by a similar source. Decisions about technical feasibility of a control option consider the physical or chemical properties of the emissions stream in comparison to emissions streams from similar sources successfully implementing the control alternative. The NSR Manual explains the concept of applicability as follows: "An available technology is 'applicable' if it can reasonably be installed and operated on the source type under consideration."[30] Applicability of a technology is determined by technical judgment and consideration of the use of the technology on similar sources as described in the NSR Manual.

10.2.3. Step 3 - Rank Remaining Control Technologies by Control Effectiveness

All remaining technically feasible control options are ranked based on their overall control effectiveness for GHG. For GHGs, this ranking may be based on energy efficiency and/or emission rate.

10.2.4. Step 4 - Evaluate Most Effective Controls and Document Results

After identifying and ranking available and technically feasible control technologies, the economic, environmental, and energy impacts are evaluated to select the best control option. If adverse collateral impacts do not disqualify the top-ranked option from consideration it is selected as the basis for the BACT limit. Alternatively, in the judgment of the permitting agency, if unreasonable adverse economic, environmental, or energy impacts are associated with the top control option, the next most stringent option is evaluated. This process continues until a control technology is identified. EPA recognized in its BACT guidance for GHGs that "[e]ven if not eliminated at Step 2 of the BACT analysis, on the basis of the current costs of CCS, we expect that CCS will often be eliminated from consideration in Step 4 of the BACT analysis, even in some cases where underground storage of the captured CO_2 near the power plant is feasible."[31]

Permitting authorities have historically considered the effects of multiple pollutants in the application of BACT as part of the PSD review process, including the environmental impacts of collateral emissions resulting from the implementation of emission control technologies. To clarify the permitting agency's expectations with respect to the BACT evaluation process, states have sometimes prioritized the reduction of one pollutant above another. For example, technologies historically used to control NO_X emissions frequently caused increases in CO emissions. Accordingly, several states prioritized the reduction of NO_X emissions above the reduction of CO emissions, approving low NO_X control strategies as BACT that result in higher CO emissions relative to the uncontrolled emissions scenario.

The energy, environment, and economic impacts analysis under Step 4 of a GHG BACT assessment presents a unique challenge with respect to the evaluation of CO_2 and CH_4 emissions. The technologies that are most frequently used to control emissions of CH_4 in hydrocarbon-rich streams (e.g., flares and thermal oxidizers) actually convert CH_4 emissions to CO_2 emissions. Consequently, the reduction of one GHG (i.e., CH_4) results in a proportional increase in emissions of another GHG (i.e., CO_2). However, since the Global Warming Potential (GWP) of CH_4 is 21 times higher than CO_2, conversion of CH_4 emissions to CO_2 results in a net reduction of CO_2e emissions.

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[29] NSR Workshop Manual (Draft), Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) Permitting, page B.18.

[30] Ibid.

[31] General GHG Permitting Guidance at 42-43.

10.2.5. Step 5 - Select BACT

In the final step, the BACT emission limit is determined for each emission unit under review based on evaluations from the previous step.

Although the first four steps of the top-down BACT process involve technical and economic evaluations of potential control options (i.e., defining the appropriate technology), the selection of BACT in the fifth step involves an evaluation of emission rates achievable with the selected control technology. BACT is an emission limit unless technological or economic limitations of the measurement methodology would make the imposition of an emissions standard infeasible, in which case a work practice or operating standard can be imposed.

Establishing an appropriate averaging period for the BACT limit is a key consideration under Step 5 of the BACT process. Localized GHG emissions are not known to cause adverse public health or environmental impacts. Rather, EPA has determined that GHG emissions are anticipated to contribute to long-term environmental consequences on a global scale. Accordingly, EPA's Climate Change Work Group has characterized the category of regulated GHGs as a "global pollutant." Given the global nature of impacts from GHG emissions, EPA has not established National Ambient Air Quality Standards (NAAQS) for GHGs, and a dispersion modeling analysis for GHG emissions is not a required element of a PSD permit application for GHGs. Since localized short-term health and environmental effects from GHG emissions are not recognized, Targa proposes only an annual average GHG BACT limit.

10.3. GHG BACT REQUIREMENT

The GHG BACT requirement applies to each new emission unit from which there are emissions increases of GHG pollutants subject to PSD review. The proposed Longhorn Gas Plant is a new major source with respect to GHG. The estimated GHG emissions from the proposed facility will be greater than 100,000 tpy on a CO_2e basis primarily due to separation of CO_2 from the raw natural gas feed stream and the combustion of fuel in process heaters.

Potential emissions of GHGs from the proposed Longhorn Gas Plant will result from the following emission units:

- Three natural gas heaters (EPN 1, 3, 4);
- One amine treating unit (EPN 15);
- One TEG dehydrator (EPN 2);
- One RTO (EPN 5);
- Start-up activities from the RTO (EPN-5-MSS);
- One flare (EPN 6, 6-MSS);
- Fugitive emissions from piping components (EPN FUG-1); and
- Fugitive emissions from maintenance, start-up and shutdown activities (EPNs 7-MSS, 8-MSS, EPN FUG-MSS).

Targa is also proposing to construct nine storage tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18) and to conduct truck loading operations (EPN FUG-2). However, based on the characteristics of the tank contents, GHG emissions from the tanks and loading equipment have been determined to be negligible and emission estimates for these operations are not included in this GHG PSD permit application.

This BACT analysis focuses mainly on the predominant sources of CO_2e from the project. GHG emissions from small emission sources such as MSS activities are not included in the BACT analysis.

The emission calculations provided in Section 7 include a summary of the estimated maximum annual potential to emit GHG emission rates for the proposed Longhorn Gas Plant. GHG emissions for each emission unit were estimated based on proposed equipment specifications as provided by the manufacturer and the default emission factors in the EPA's Mandatory Greenhouse Gas Reporting Rule (40 CFR 98, Subpart C and Subpart W).

The following guidance documents were utilized as resources in completing the GHG BACT evaluation for the proposed project:

- PSD and Title V Permitting Guidance For Greenhouse Gases (hereafter referred to as General GHG Permitting Guidance)[32]
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Industrial, Commercial, and Institutional Boiler (hereafter referred to as GHG BACT Guidance for Boilers)[33]
- Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry (hereafter referred to as GHG BACT Guidance for Refineries)[34]

10.4. GHG BACT EVALUATION FOR PROPOSED EMISSION SOURCES

The following is an analysis of BACT for the control of GHG emissions from the proposed Longhorn Gas Plant following the EPA's five-step "top-down" BACT process. The table at the end of this section summarizes each step of the BACT analysis for the emission units included in this review. Targa is proposing the use of good combustion practices for all combustion sources at the proposed facility. A table detailing good combustion practices is included at the end of this section.

Table 10.4-1 provides a summary of the proposed BACT limits discussed in the following sections.

Table 10.4-1. Proposed GHG BACT Limits for Longhorn Gas Plant

EPN	Description	Proposed BACT Limit (CO_2e tpy)
1	TEG-1 Glycol Reboiler	1,025
3	HTR-1 Regen Heater	6,355
4	HTR-2 Hot Oil Heater	50,223
5	RTO-1 Regen Thermal Oxidizer	116,292
6	Flare-1 Flare (Pilot)	77
5-MSS	RTO-1 Startup	1.4
15-MSS	Amine Still Vent During RTO Downtime	2,027
2-MSS	TEG Dehydrator During RTO Downtime	5

Detailed BACT analysis is conducted for major CO_2e contributors.

10.5. OVERALL PROJECT ENERGY EFFICIENCY CONSIDERATIONS

While the five-step BACT analysis is the EPA's preferred methodology with respect to selection of control technologies for pollutants, EPA has also indicated that an overarching evaluation of energy efficiency should take place as increases in energy efficiency will inherently reduce the total amount of GHG emissions produced by the source. As

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

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

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

such, overall energy efficiency was a basic design criterion in the selection of technologies and processing alternatives to be installed at the proposed Longhorn Gas Plant.

The new 200 MMscfd Longhorn Gas Processing Plant will be designed and constructed using all new, energy efficient equipment. The plant is designed for deep ethane recovery using minimal fuel and power. This is accomplished using a state of the art recovery process, incorporating multiple exchangers for maximum heat recovery and utilizing an efficient non-powered turbo- expander. This facility will utilize high pressure gas for efficient product recovery.

The facility is completely electric-driven from an existing high voltage transmission line located adjacent to the property. There will be three (3) electric-driven compressors for residue compression. The plant's refrigeration system utilizes all electric compression using screw type compressors for propane circulation. This is much more efficient with considerably less emissions potential (e.g., packing, fugitive points) than a reciprocating compressor in this service.

Many of the required electric pumps and one of the large residue compressors in the plant are controlled by Variable Frequency Drives (VFDs) that reduce electrical consumption by varying motor speed in response to control inputs. Since motors/pumps are rarely needed at maximum speed under normal operations, this lowers electrical consumption considerably. The product pumps containing VOCs and the hot oil pumps containing heavy oil will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when the first seal begins to leak.

The plant will utilize UCARSOL AP-814 as the amine treating fluid because of its affinity for CO_2. This amine is more expensive but requires the lowest circulation rates and lowest heat duties (i.e., less fuel) to treat the inlet gas than other amine solutions.

In dehydrating, typical glycol units are sized for a water content of 7 lbs per MMcf of outlet gas. The Longhorn unit has been sized for minimal circulation and minimal heat duty. It will dehydrate just enough to allow the mole sieve beds to dehydrate effectively.

The vents from the amine unit and dehydrator will be routed to an RTO to assure complete destruction of VOCs and hazardous components. The more expensive RTO was chosen over a standard oxidizer to reduce fuel consumption and emissions rates, resulting in a difference in fuel efficiency from 65% to 98%. The glycol vent will be condensed and recycled to the reboiler fuel to be burned. All water accumulated from the amine unit and glycol unit will be recycled back to their respective systems.

The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. In addition, all pressure safety valves (PSVs) relieving heavier-than-air components will be routed in a closed system to a smokeless flare stack for effective combustion, as will all compressor blowdown vents. Inlet gas separator liquids will be re-injected back into the pipeline for handling at another facility.

The facility will have a closed drain system for collection of incidental condensate from process scrubbers and dumps. This will be equipped with a vapor recovery unit (VRU)-controlled flash tank that routes any vapors back to the plant fuel system for burning. All major skids and equipment containing ground-contaminating liquids will have concrete pads underneath extending out 3 feet from all sides to facilitate maintenance and to collect any drips or spills underneath. Compressor packages will have drip rails installed on skids to contain and collect oil drips and spills.

10.6. BENEFITS OF ELECTRIC MOTORS

Electric motors, in comparison to other driver alternatives, (1) produce no GHG emissions, (2) do not have their energy efficiency affected by weather or add-on control technologies, (3) have more efficient turndown characteristics for variable output operations, (4) can be sized to allow for a more efficient design and (5) have no waste heat which is readily usable with the design of the Longhorn Gas Plant. With respect to weather-related inefficiencies, other primary driver alternatives typically lose efficiency (i.e., become de-rated) as temperatures and humidity levels deviate from the design conditions used to engineer the applicable driver.

Selecting electric motors as the primary drivers for the large compressors and pumps at the Longhorn Gas Plant avoids these inefficiencies. In addition, other primary driver alternatives which produce GHG emissions would likely utilize add-on control technologies (such as selective catalytic reduction units) which cause additional energy inefficiencies for the driver. Once operational, the Longhorn Gas Plant will be operated at varying rates due to, among other things, changes in customer demands and variations in the inlet natural gas supply.

When coupled with variable speed drives (which will be used at the Longhorn Gas Plant), electric motors remain efficient within a larger operating envelope than other primary driver alternatives. In other words, electric motors have more efficient turndown characteristics. Furthermore, electric motors are supplied in a greater number of standard sizes which allows Targa to select a motor size that is optimal to the desired design output required by the project. If a different primary driver was selected, the size of the driver would determine the design output of the train rather than vice versa, which would lead to Targa having to design a train size which is larger than desired, thus losing energy efficiency through over-sizing of equipment. Finally, other primary driver alternatives typically generate a significant amount of heat as a by-product of their operation which, in some instances, can be utilized to increase the efficiency of those drivers (such as through the use of heat recovery steam generator units).

10.7. PROCESS HEATERS

GHG emissions from the proposed process heaters include CO_2, CH_4 and N_2O and result from the combustion of natural gas. The heaters include a hot oil heater, a mole sieve regenerator heater, and a glycol dehydrator reboiler. The following section presents BACT evaluations for GHG emissions from the proposed process heaters.

10.7.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for process heaters that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Good Combustion Practices, Operating, and Maintenance Practices;
- Oxygen Trim Controls;
- Fuel Gas Pre-heater / Air Pre-heater; and
- Efficient Heater Design.

10.7.1.1. Carbon Capture and Sequestration

As previously discussed, this project's CO_2e emissions profile is a fraction of the scale for sources where CCS might ultimately be feasible. Although we believe that it is obvious that CCS is not BACT in this case, as directly supported in EPA's GHG BACT Guidance, a detailed rationale is provided to support this conclusion.

For the process heaters, CCS would involve post combustion capture of the CO_2 from the heaters and sequestration of the CO_2 in some fashion. In general, carbon capture could be accomplished with low pressure scrubbing of CO_2 from the exhaust stream with solvents (e.g., amines and ammonia), solid sorbents, or membranes. However, only solvents have been used to-date on a commercial (yet slip stream) scale and solid sorbents and membranes are only in the research and development phase. A number of post-combustion carbon capture projects have taken place on slip streams at coal-fired power plants. Although these projects have demonstrated the technical feasibility of small-scale CO_2 capture on a slipstream of a power plant's emissions using various solvent based scrubbing processes, until these post-combustion technologies are installed fully on a power plant, they are not considered "available" in terms of BACT.

Larger scale CCS demonstration projects have been proposed through the DOE Clean Coal Power Initiative (CCPI); however, none of these facilities are operating, and, in fact, they have not yet been fully designed or constructed.[35] Additionally, these demonstration projects are for post-combustion capture on a pulverized coal (PC) plant using a slip stream versus the full exhaust stream. Also, the exhaust from a PC plant would have a significantly higher concentration of CO_2 in the slipstream as compared to a more dilute stream from the combustion of natural gas.[36] In addition, the compression of the CO_2 would require additional power demand, resulting in additional fuel consumption (and CO_2 emissions).[37]

10.7.1.2. Fuel Selection

Natural gas has the lowest carbon intensity of any available fuel for the process heaters. The proposed process heaters will be fired with only natural gas fuel.

10.7.1.3. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option by improving the fuel efficiency of the process heaters. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.

10.7.1.4. Oxygen Trim Controls

Combustion units operated with too much excess air may lead to inefficient combustion, and additional energy will be needed to heat the excess air. Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. [38]

10.7.1.5. Fuel Gas Pre-heater / Air Pre-heater

Preheating the fuel gas and air reduces heating load and increases thermal efficiency of the combustion unit. An air pre-heater recovers heat in the heater exhaust gas to preheat combustion air. Preheating the combustion air in this way reduces heater heating load, increases its thermal efficiency, and reduces emissions.

10.7.1.6. Efficient Heater Design

Efficient heater design and proper air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer. Since Targa is proposing to install new heaters, these heaters will be designed to optimize combustion efficiency. Additionally, as discussed in Section 10.5, the amine treater and TEG dehydrator have been designed to minimize heat duty and require less fuel to treat inlet gas.

10.7.2. Step 2 – Eliminate Technically Infeasible Options

As discussed below, CCS and fuel gas/air preheating are deemed technically infeasible for control of GHG emissions from the process heaters. All other control options are technically feasible.

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[35] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. 32.

[36] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, p. A-7.

[37] Report of the Interagency Task Force on Carbon Capture & Storage, August 2010, http://www.epa.gov/climatechange/downloads/CCS-Task-Force-Report-2010.pdf, p. 29

[38] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from the Petroleum Refining Industry*, U.S. EPA, October 2010, Section 3.

10.7.2.1. Carbon Capture and Sequestration

The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the process heaters and is therefore infeasible. This is supported by EPA's assertion that CCS is considered "available" for projects that emit CO_2 in "large" amounts.[39] This project and these emission units, by comparison, emit CO_2 in small quantities. Therefore, CCS is not considered a technically, economically, or commercially viable control option for the proposed process heaters. CCS is not considered as a control option for further analysis.

10.7.2.2. Fuel Gas Pre-heater / Air Pre-heater

Fuel gas/air preheating is not feasible for small heaters. This is more suitable for large boilers (>100 MMBtu/hr). In addition, these options may increase NO_X emissions.

10.7.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS and fuel gas/air preheating as control options, the following remain as technically feasible control options for minimizing GHG emissions from the process heaters:

- low carbon fuel selection,
- implementation of good combustion, operating, and maintenance practices,
- installation of oxygen trim controls, and
- efficient heater design.

Since Targa proposes to implement all of these control options, ranking these control options is not necessary.

10.7.4. Step 4 – Evaluate Most Effective of Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

10.7.5. Step 5 – Select BACT for the Process Heaters

Targa proposes the following design elements and work practices as BACT for the process heaters:

- use of natural gas as fuel;
- implementation of good combustion, operating, and maintenance practices;
- oxygen trim control; and
- efficient heater design.

Targa proposes the CO_2e emission limits for the heaters:

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[39] *PSD and Title V permitting Guidance for Greenhouse Gases.* March 2011, page 32. *"For the purposes of a BACT analysis for GHGs, EPA classifies CCS as an add-on pollution control technology[86] that is "available"[87] for facilities emitting CO_2 in large amounts, including fossil fuel-fired power plants, and for industrial facilities with high-purity CO_2 streams (e.g., hydrogen production, ammonia production, natural gas processing, ethanol production, ethylene oxide production, cement production, and iron and steel manufacturing).* The proposed project is not any of the cases EPA suggests above.

- TEG-2 Glycol Reboiler (EPN 1): 1,025 short tons of CO_2e per year
- HTR-1 Regeneration Heater (EPN 3): 6,355 short tons of CO_2e per year
- HTR-2 Hot Oil Heater (EPN 4): 50,223 short tons of CO_2e per year

These proposed emission limits are based on a 12-month rolling average basis and include CO_2, CH_4, and N_2O emissions, with CO_2 emissions being more than 99% of the total emissions.

Compliance with these emission limits will be demonstrated by monitoring fuel consumption and performing calculations consistent with the calculations included in Section 7 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average short tons of CO_2e per year emission rates do not exceed these limits.

10.8. AMINE UNIT AND TEG DEHYDRATOR / REGENERATIVE THERMAL OXIDIZER

The amine unit at the Longhorn Gas Plant will be used to remove CO_2 in order to meet pipeline quality natural gas specifications. The TEG dehydration unit will be used to remove water from the gases. Stripped amine acid gases and dehydrator waste gases will be routed to an RTO. GHG emissions from the RTO result from routing removed CO_2 from the amine unit to the RTO and the combustion of process waste gases from the amine unit and the dehydrator unit. The process-based CO_2 emissions emitted from the RTO are calculated based on the estimated flow rates and gas composition of amine acid and dehydrator waste gases routed to the RTO. Any VOCs and CH_4 emissions present in the vent gas routed to the RTO will be converted to CO_2 in the combustion zone, and CO_2 has a lower GWP compared to CH_4.

The RTO will utilize a gas-fired burner system to bring the RTO up to combustion temperature during startup. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine and dehydrator waste streams alone to support combustion. Emissions from the startup burner system will result from the combustion of pipeline quality natural gas.

GHG emissions from the routing of CO_2 from the TEG dehydrator waste gas and the combustion of VOCs and CH_4 in the dehydrator waste gas stream are very small relative to the total GHG emissions from the RTO (i.e., 1,146 tpy CO_2e or less than 1% of the total RTO CO_2e emissions). Additionally, GHG emissions from the combustion of natural gas in the startup burner system are very small (i.e., 1.40 tpy CO_2e or approximately 0.001% of the total RTO GHG emissions). Therefore, the BACT analysis addresses GHG emissions related to the amine waste streams only.

10.8.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control options for the process emissions sent to the RTO include:

- Carbon Capture and Sequestration

The available GHG emission control strategies for the RTO combustion emissions include:

- Carbon Capture and Sequestration
- Proper RTO Design, Operation, and Maintenance
- Fuel Selection
- Good Combustion Practices

10.8.1.1. Carbon Capture and Sequestration

Targa conducted research and analysis to determine the technical feasibility of CO_2 capture and transfer. Since most of the CO_2 emissions from the proposed project are generated from the amine units, Targa conducted studies to evaluate potential options to capture and transfer the CO_2 to an off-site facility for injection.

Based on the results of these studies, capture and transfer of CO_2 from the amine treatment units is technically feasible. A study was performed to evaluate the potential options for capture and transfer of CO_2 from the Longhorn Gas Plant (located near Decatur in Wise County, TX) to nearby CO_2 injection wells. The transfer of the CO_2 stream will require further treatment to remove contaminants and compression for transfer via a new pipeline.

Since capture and transfer of CO_2 for off-site transfer is technically feasible for the proposed project, this option is further evaluated for energy, environmental, and economic impacts.

10.8.1.2. Proper RTO Design, Operation, and Maintenance

Good RTO design can be employed to destroy any VOCs and CH_4 entrained in the waste gas from the amine unit and the TEG dehydrator unit. Good RTO design includes flow measurement and monitoring/control of waste gas heating values. In addition, periodic tune-up and maintenance will be performed per the manufacturer recommendation. As discussed in Section 10.5, the more expensive RTO was chosen over a standard oxidizer to reduce fuel consumption and emissions rates (a difference in efficiency from 65% to 98%).

10.8.1.3. Fuel Selection

The fuel for firing the proposed RTO will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel for the RTO. In addition, the RTO will utilize the gas-fired burner system to bring the RTO up to combustion temperature during startup only. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine and dehydrator waste streams alone to support combustion.

10.8.1.4. Good Combustion Practices

Good combustion practices are a potential control option for improving the fuel efficiency of the RTO. Good combustion practices include proper maintenance and tune-up of the RTO.

10.8.2. Step 2 – Eliminate Technically Infeasible Options

All control options identified in Step 1 are technically feasible.

10.8.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

CCS (i.e., sequestration or transfer of CO_2) is the most effective control option for the control of the CO_2 streams from the amine unit to the RTO, since it provides approximately 90% CO_2 control of the amine acid gas stream, based on literature review.

Good RTO design and operation result in approximately 1-15% and 1-10% reduction in GHG emissions, respectively.[40]

Low carbon fuel selection and the implementation of good combustion, operating, and maintenance practices are technically feasible control options for minimizing GHG emissions from fuel combustion.

[40] *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Petroleum Refining Industry,* U.S. EPA, October 2010, Section 3.

10.8.4. Step 4 – Evaluate Most Effective Control Options

The only technically feasible technology listed in Step 3 that may have additional energy, environmental, and economic impacts is CO_2 capture and transfer.

While the process exhaust stream from the RTO is relatively high in CO_2 content, additional processing of the exhaust gas will be required to implement CCS. These include separation (removal of other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream. These processes require additional equipment to reduce the exhaust temperature, compress the gas, and transport the gas via pipelines. These units would require additional electricity and generate additional air emissions, of both criteria pollutants and GHG pollutants. This would result in negative environmental and energy impacts.

As part of the CO_2 transfer feasibility analysis, Targa reviewed currently active CO_2 injection wells identified on the Texas Railroad Commission (RRC) website in and around Wise County (District No. 9) and adjacent districts (District Nos. 5 and 7B).[41] This website provides the details of registered wells and permitted fluids for injection. Most of the wells are permitted to inject saltwater, CO_2, or natural gas. Targa refined the search to limit to wells that are permitted for and reported injection of CO_2. Based on the aerial distance from the proposed Longhorn Gas Plant, the nearest CO_2 injection well is located at 110 miles. A map of the location of the proposed Longhorn Gas Plant and the nearest well is included in Appendix C.

As can be seen in the map, a CO_2 transfer pipeline laid straight from the Longhorn Gas Plant to this well would need to pass through the Dallas-Fort Worth (DFW) Metroplex, which is not technically, economically, or environmentally feasible. Therefore, the actual length of a transfer pipeline would be much greater than 110 miles. For cost estimation purposes, a pipeline length of 110 miles is used to be conservative.

The cost of pipeline installation and operation are obtained from the National Energy Technology Laboratory (NETL)'s Document Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447. Per this document, the pipeline costs include pipeline installation costs, other related capital costs, and operation and maintenance (O&M) costs. A copy of this document is included in Appendix D to provide additional details and assumptions in this study.

Using the cost estimation methods from the NETL document, the cost of capture, compression, and transfer of CO_2 via a pipeline was estimated to be approximately $108 per ton of CO_2 removed from the RTO. A detailed cost analysis is included in Appendix E. The cost estimation does not include additional capital costs incurred to compression equipment and other process equipment such as cryogenic units.

Therefore, based on the pipeline transfer cost, although technically feasible, off-site transfer is not regarded as a viable or economically feasible CO_2 control option. Additionally, CO_2 capture and transfer would have negative environmental and energy impacts, as discussed above.

10.8.5. Step 5 – Select BACT for the RTO

Targa proposes the following design elements and work practices as BACT for the RTO:

- Proper RTO design, operation, and maintenace; and
- Use of natural gas as fuel.

[41] Injection and Disposal Query available at Texas RRC website at: http://webapps2.rrc.state.tx.us/EWA/uicQueryAction.do

In addition, Targa proposes a numerical BACT limit for total GHG emissions emitted from the RTO during normal operation to 116,170.13 short tons of CO_2e per year (based on a 12-month rolling average). These emissions include process related emissions from both the amine treater and the TEG dehydrator.

Compliance with these emission limits and throughput limits will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with those in Section 7 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and short tons of CO_2e per year emission rates do not exceed these limits.

10.9. FLARE

The flare at the Longhorn Gas Plant will be used to destroy the off-gas produced during emergency situations and during planned MSS activities. GHG emissions will be generated by the combustion of natural gas as well as combustion of the vent gas to the flare.

CO_2 emissions from flaring process gas are produced from the combustion of carbon-containing compounds (e.g., VOCs, CH_4) present in the vent streams routed to the flare during MSS events and the pilot fuel. CO_2 emissions from the flare are based on the estimated flared carbon-containing gases derived from heat and material balance data. In addition, minor CH_4 emissions from the flare are produced due to incomplete combustion of CH_4.

The flares are 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, it is appropriate to apply combustion controls to CH_4 emissions even though it will form additional CO_2 emissions.[42]

The following sections present a BACT evaluation for GHG emissions from combustion of pilot gas and vent gas released to the flare during planned startup and shutdown events.

10.9.1. Step 1 – Identify All Available Control Technologies

The available GHG emission control strategies for the flare that were analyzed as part of this BACT analysis include:

- Carbon Capture and Sequestration;
- Fuel Selection;
- Flare Gas Recovery;
- Good Combustion, Operating, Maintenance Practices;
- Good Flare Design; and
- Limited vent gas releases to flare

10.9.1.1. Carbon Capture and Sequestration

A detailed discussion of CCS technology is provided in Section 10.8.

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[42] For example, combusting 1 lb of CH_4 (21 lb CO_2e) at the flare will result in 0.02 lb CH_4 and 2.7 lb CO_2 (0.02 lb CH_4 x 21 CO_2e/CH_4 + 2.7 lb CO_2 x 1 CO_2e/CO_2 = 2.9 lb CO_2e), and therefore, on a CO_2e emissions basis, combustion control of CH_4 is preferable to venting the CH_4 uncontrolled.

10.9.1.2. Fuel Selection

The pilot gas fuel for the proposed flare will be limited to natural gas fuel. Natural gas has the lowest carbon intensity of any available fuel.

10.9.1.3. Flare Gas Recovery

Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable.

10.9.1.4. Good Combustion, Operating, and Maintenance Practices

Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare at least annually per the manufacturer's specifications.

10.9.1.5. Good Flare Design

Good flare design can be employed to destroy large fractions of the flare gas. Much work has been done by flare and flare tip manufacturers to assure high reliability and destruction efficiencies. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.

10.9.1.6. Limited Vent Gas Releases to Flare

Minimizing the number and duration of MSS activities and therefore limiting vent gases routed to the flare will help reduce emissions from MSS activities.

10.9.2. Step 2 – Eliminate Technically Infeasible Options

The technical infeasibility of CCS and flare gas recovery is discussed below. All other control technologies listed in Step 1 are considered technically feasible.

10.9.2.1. Carbon Capture and Sequestration

With no ability to collect exhaust gas from a flare other than using an enclosure, post combustion capture is not an available control option. Pre-combustion capture has not been demonstrated for removal of CO_2 from intermittent process gas streams routed to a flare. Flaring will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates resulting in a very intermittent CO_2 stream; thus, CCS is not considered a technically feasible option. Therefore, it has been eliminated from further consideration in the remaining steps of the analysis.

10.9.2.2. Flare Gas Recovery

Installing a flare gas recovery system to recover flare gas to the fuel gas system is considered a feasible control technology for industrial process flares. Flaring at the Longhorn Gas Plant will be limited to emergency situations and during planned startup and shutdown events of limited duration and vent rates. Due to infrequent MSS activities and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control. Therefore, the amount of flare gas produced by this project will not sustain a flare gas recovery system. For this project, flare gas recovery is infeasible.

10.9.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

With elimination of CCS and flare gas recovery as technically infeasible control options, the following control options remain as technically feasible control options for minimizing GHG emissions from the flare:

- Fuel selection
- Good combustion, operating, and maintenance practices
- Good flare design
- Limited vent gas releases to flare

Since Targa proposes to implement all of these control options, ranking these control options is not necessary.

10.9.4. Step 4 – Evaluate Most Effective Control Options

No significant adverse energy or environmental impacts (that would influence the GHG BACT selection process) associated with the above-mentioned technically feasible control options are expected.

10.9.5. Step 5 – Select BACT for the Flares

Targa proposes the following design elements and work practices as BACT for the flare:

- use of natural gas as fuel;
- implementation of good combustion, operating, and maintenance practices;
- good flare design; and
- limiting vent gas releases to the flare.

The flare will meet the requirements of 40 CFR §60.18, and will be properly instrumented and controlled. Emission sources, such as electric compressors, whose MSS emissions are routed to the flare will be operated in manner to minimize the frequency and duration of such MSS activities and therefore, the amount of MSS vent gas released to the flare.

Targa proposes the following as numerical BACT limits for GHG emissions associated with pilot gas combustion to no more than 77 tpy of CO_2e. Compliance with these throughput limits will be demonstrated by monitoring inlet gas throughput rate and performing calculations consistent with those in Section 7 of this application. These calculations will be performed on a monthly basis to ensure that the 12-month rolling average throughput and short tons of CO_2e per year emission rates do not exceed this limit.

10.10. FUGITIVE COMPONENTS

The following sections present a BACT evaluation of fugitive CO_2 and CH_4 emissions. It is anticipated that the fugitive emission controls presented in this analysis will provide similar levels of emission reduction for both CO_2 and CH_4. Fugitive components at the proposed Longhorn Gas Plant include traditional components (valves, flanges, pressure relief valves, pumps, compressors, and connectors), O_2 sensors, and gas chromatographs.

10.10.1. Step 1 - Identify All Available Control Technologies

In determining whether a technology is available for controlling GHG emissions from fugitive components, permits and permit applications and EPA's RBLC were consulted. Based on these resources, the following available control technologies were identified and are discussed below:

- Installing leakless technology components to eliminate fugitive emission sources;
- Installing air-driven pneumatic controllers;
- Implementing various LDAR programs in accordance with applicable state and federal air regulations;
- Implementing an alternative monitoring program using a remote sensing technology such as infrared camera monitoring;
- Implementing an audio/visual/olfactory (AVO) monitoring program for odorous compounds; and

- Designing and constructing facilities with high quality components and materials of construction compatible with the process.

10.10.1.1. Leakless Technology Components

Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used. These technologies are generally considered cost prohibitive except for specialized service. Some leakless technologies, such as bellows valves, if they fail, cannot be repaired without a unit shutdown which often generates additional emissions.

10.10.1.2. Air-Driven Pneumatic Controllers

Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.

10.10.1.3. LDAR Programs

LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs. Monitoring direct emissions of CO_2 is not feasible with the normally used instrumentation for fugitive emissions monitoring. However, instrumented monitoring is technically feasible for components in CH_4 service.

10.10.1.4. Alternative Monitoring Program

Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.

10.10.1.5. AVO Monitoring Program

Leaking fugitive components can be identified through AVO methods. The fuel gases and process fluids at the Longhorn Gas Plant piping components are expected to have discernable odor, making them detectable by olfactory means. A large leak can be detected by sound (audio) and sight. The visual detection can be a direct viewing of leaking gases, or a secondary indicator such as condensation around a leaking source due to cooling of the expanding gas as it leaves the leak interface. AVO programs are common and in place in industry.

10.10.1.6. High Quality Components

A key element in the control of fugitive emissions is the use of high quality equipment that is designed for the specific service in which it is employed. For example, a valve that has been manufactured under high quality conditions can be expected to have lower runout on the valve stem, and the valve stem is typically polished to a smoother surface. Both of these factors greatly reduce the likelihood of leaking.

10.10.2. Step 2 – Eliminate Technically Infeasible Options

Recognizing that leakless technologies have not been universally adopted as LAER or BACT, even for toxic or extremely hazardous services, it is reasonable to state that these technologies are impractical for control of GHG emissions whose impacts have not been quantified. Any further consideration of available leakless technologies for GHG controls is unwarranted.

All other control options are considered technically feasible.

10.10.3. Step 3 – Rank Remaining Control Technologies by Control Effectiveness

10.10.3.1. Air-Driven Pneumatic Controllers

Installing air-driven pneumatic controllers will result in no GHG emissions to the atmosphere.

10.10.3.2. LDAR Programs

Instrumented monitoring is effective for identifying leaking CH_4, but may be wholly ineffective for finding leaks of CO_2. With CH_4 having a global warming potential greater than CO_2, instrumented monitoring of the fuel and feed systems for CH_4 would be an effective method for control of GHG emissions. Quarterly instrumented monitoring with a leak definition of 500 ppmv (2,000 ppmv for pumps and compressors), accompanied by intense directed maintenance, is generally assigned a control effectiveness of 97% (85% for pumps and compressors). [43]

10.10.3.3. Alternative Monitoring Program

Remote sensing using infrared imaging has proven effective for identification of leaks including CO_2. The process has been the subject of EPA rulemaking as an alternative monitoring method to the EPA's Method 21. Effectiveness is likely comparable to EPA Method 21 when cost is included in the consideration.

10.10.3.4. AVO Monitoring Program

Audio/Visual/Olfactory means of identifying leaks owes its effectiveness to the frequency of observation opportunities. Those opportunities arise as operating technicians make rounds, inspecting equipment during those routine tours of the operating areas. This method cannot generally identify leaks at a low a leak rate as instrumented reading can identify; however, low leak rates have lower potential impacts than do larger leaks. This method, due to frequency of observation is effective for identification of larger leaks.

10.10.3.5. High Quality Components

Use of high quality components is effective in preventing emissions of GHGs, relative to use of lower quality components.

10.10.4. Step 4 – Evaluate Most Effective Control Options

No adverse energy, environmental, or economic impacts are associated with the above-mentioned technically feasible control options.

10.10.5. Step 5 – Select BACT for Fugitive Emissions

Targa proposes to implement the most effective remaining control options. The plant will run on compressed air for instrument control. No process gas will be utilized or vented for these applications. Instrumented monitoring implemented through the 28 VHP LDAR program, with control effectiveness of 97% for most equipment, is considered top-level BACT.

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[43] TCEQ published BACT guidelines for fugitive emissions in the document *Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.*

In addition, Targa will utilize an AVO program to monitor for leaks in between instrumented checks. The proposed project will also utilize high-quality components and materials of construction, including gasketing, that are compatible with the service in which they are employed.

The product pumps containing VOCs, and potentially CH_4 and CO_2, will have tandem seals equipped with detection or alarm points to eliminate seal leakage and alert personnel when the first seal begins to leak.

Since Targa is implementing the most effective control options available, additional analysis is not necessary.

Targa is not proposing a numerical BACT limit on GHG emissions from fugitive components since fugitive emissions are estimates only.

Top-Down BACT Analysis for GHG Emission Sources

Emission Unit	Pollutant	Step -1: Available Control Methods		Step 2: Eliminate Technically Infeasible Options	Step 3: Rank Remaining Options Based on Control Efficiency	Step 4: Evaluate Remaining Control Technologies	Step 5: Selected as BACT?
Facility-Wide	GHGs	Overall Energy Efficiency	Design and construction using all new, energy efficient equipment. Electric engines for compression. Electric motors with variable speed drives. Seals equipped with detection or alarm points. Design specifications of the amine treater and TEG dehydrator to reduce heat duty. RTO that will burn natural gas during startup only and will operate on waste gas heat alone during normal operation. Compressed air for instrument control.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
Process Heaters (Combustion Emissions)	GHGs	Carbon Capture and Sequestration (CCS)	CCS includes separation (removal of other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream.	Technically Infeasible. The feasibility of CCS is highly dependent on a continuous CO_2-laden exhaust stream, and CCS has not been tested or demonstrated for such small combustion sources. Given the limited deployment of only slipstream/demonstration applications of CCS and the quantity and quality of the CO_2 emissions stream, CCS is not commercially available as BACT for the process heaters and is therefore infeasible.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Fuel Selection	Natural gas has the lowest carbon intensity of any available fuel for the heaters.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Good Combustion Operating, and Maintenance Practices	Good combustion and operating practices are a potential control option by improving the fuel efficiency of the process heaters. Good combustion practices also include proper maintenance and tune-up of the process heaters at least annually per the manufacturer's specifications.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Oxygen Trim Controls	Oxygen monitors and intake air flow monitors can be used to optimize the fuel/air mixture. Combustion units operated with too much excess air may lead to inefficient combustion and additional energy will be needed to heat the excess air.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Fuel Gas Pre-heater / Air Pre-heater	Preheating the fuel gas and air reduces heating load and increases thermal efficiency of the combustion unit. An air pre-heater recovers heat in the heater exhaust gas to preheat combustion air. Preheating the combustion air in this way reduces heater heating load, increases its thermal efficiency, and reduces emissions.	Technically Infeasible. Fuel gas/air preheating is not feasible for small heaters. This is more suitable for large boilers (>100 MMBtu/hr). In addition, these options may increase NO_X emissions.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Efficient Heater Design	Efficient heater design and air-to-fuel ratio improve mixing of fuel and create more efficient heat transfer.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes

Top-Down BACT Analysis for GHG Emission Sources

Emission Unit	Pollutant	Step -1: Available Control Methods		Step 2: Eliminate Technically Infeasible Options	Step 3: Rank Remaining Options Based on Control Efficiency	Step 4: Evaluate Remaining Control Technologies	Step 5: Selected as BACT?
Amine Unit and TEG Dehydrator / Thermal Oxidizer (Process Emissions and Fuel Combustion Emissions)	GHGs	CCS	CCS includes separation (removal of other pollutants), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream.	Technically Feasible	90%	Economically Infeasible with Negative Environmental and Energy Impacts. The cost of pipeline transfer is not economically feasible. Additional emissions from exhaust gas processing and compression results in negative environmental and energy impacts.	No
		Proper RTO design, operation, and maintenance	Good RTO design can be employed to destroy any VOCs and CH_4 entrained in the waste gas from the amine unit and the TEG dehydrator unit. Good RTO design includes flow measurement and monitoring/control of waste gas heating values. In addition, periodic tune-up and maintenance will be performed per the manufacturer recommendation.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Fuel Selection	Natural gas has the lowest carbon intensity of any available fuel for the RTO.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Good Combustion Practices	Good combustion practices are a potential control option for improving the fuel efficiency of the RTO. Good combustion practices include proper maintenance and tune-up of the RTO.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
Flare (Pilot Gas Combustion and MSS Activities)	GHGs	CCS	CCS includes separation (removal of other pollutants from the combustion gases), capture, and compression of CO_2, transfer of the CO_2 stream and sequestration of the CO_2 stream.	Technically Infeasible. The flares are intermittent sources and capturing CO_2 from the intermittent sources is not feasible.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Fuel Selection	Natural gas has the lowest carbon intensity of any available fuel.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Flare Gas Recovery	Flaring can be reduced by installation of commercially available recovery systems, including recovery compressors and collection and storage tanks. The recovered gas is then utilized by introducing it into the fuel system as applicable.	Technically Infeasible. Due to infrequent MSS activities and the amount of gas sent to the flare, it is technically infeasible to re-route the flare gas to a process fuel system and hence, the gas will be combusted by the flare for control. The amount of flare gas produced by this project will not sustain a flare gas recovery system.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Good Combustion, Operating, and Maintenance Practices	Good combustion and operating practices are a potential control option for improving the combustion efficiency of the flare. Good combustion practices include proper operation, maintenance, and tune-up of the flare at least annually per the manufacturer's specifications.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Good Flare Design	Good flare design can be employed to destroy large fractions of the flare gas. Good flare design includes pilot flame monitoring, flow measurement, and monitoring/control of waste gas heating value.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Limited Vent Gas Releases to Flare	Minimizing the number and duration of MSS activities and therefore limiting vent gases routed to the flare will help reduce emissions from MSS activities.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes

Top-Down BACT Analysis for GHG Emission Sources

Emission Unit	Pollutant	Step -1: Available Control Methods		Step 2: Eliminate Technically Infeasible Options	Step 3: Rank Remaining Options Based on Control Efficiency	Step 4: Evaluate Remaining Control Technologies	Step 5: Selected as BACT?
Fugitive Emissions	GHGs	Installation of Leakless Equipment	Leakless technology valves are available and currently in use, primarily where highly toxic or otherwise hazardous materials are used.	Technically Infeasible. Not demonstrated for GHG emission sources.	N/A - Technically Infeasible	N/A - Technically Infeasible	No
		Installation of Air-driven Pneumatic Controllers	Air-driven pneumatic controllers utilize compressed air and therefore do not emit any GHG emissions.	Technically Feasible	100% for pneumatic controllers	N/A - Selected as BACT	Yes
		Implementation of LDAR Program	LDAR programs have traditionally been developed for the control of VOC emissions. BACT determinations related to control of VOC emissions rely on technical feasibility, economic reasonableness, reduction of potential environmental impacts, and regulatory requirements for these instrumented programs.	Technically Feasible	Up to 97%	N/A - Selected as BACT	Yes
		Alternative Monitoring Program - Remote Sensors / Infrared Technologies	Alternate monitoring programs such as remote sensing technologies have been proven effective in leak detection and repair. The use of sensitive infrared camera technology has become widely accepted as a cost effective means for identifying leaks of hydrocarbons.	Technically Feasible	N/A - Most effective control option (LDAR) is implemented	N/A - No further evaluation is required	No
		Audio/Visual/Olfactory (AVO) Monitoring Program	Leaking fugitive components can be identified through audio, visual, or olfactory (AVO) methods.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes
		Use High Quality Components and Materials of Construction Compatible with Process	The use of high quality equipment that is designed for the specific service in which it is employed results in effective control of fugitive emissions.	Technically Feasible	N/A - Selected as BACT	N/A - Selected as BACT	Yes

Summary of Proposed Good Combustion Practices [1]

Good Combustion Technique	Practice	Applicable Units	Standard
Operator practices	-Official documented operating procedures, updated as required for equipment or practice change -Procedures include startup, shutdown, malfunction -Operating logs/record keeping.	All combustion units	-Maintain written site specific operating procedures in accordance with GCPs, including startup, shutdown, malfunction.
Maintenance knowledge	-Training on applicable equipment & procedures.	All combustion units	-Equipment maintained by personnel with training specific to equipment.
Maintenance practices	-Official documented maintenance procedures, updated as required for equipment or practice change -Routinely scheduled evaluation, inspection, overhaul as appropriate for equipment involved -Maintenance logs/record keeping.	All combustion units	-Maintain site specific procedures for best/optimum maintenance practices -Scheduled periodic evaluation, inspection, overhaul as appropriate.
Firebox (furnace) residence time, temperature, turbulence	-Supplemental stream injection into active flame zone -Residence time by design (incinerators) -Minimum combustion chamber temperature (incinerators).	Thermal Oxidizer and Flare	
Fuel quality analysis and fuel handling	-Monitor fuel quality -Fuel quality certification from supplier if needed -Periodic fuel sampling and analysis -Fuel handling practices - Targa Longhorn Gas Plant will use pipeline quality natural gas.	All combustion units	-Fuel analysis where composition could vary -Fuel handling procedures applicable to the fuel.
Combustion air distribution	-Adjustment of air distribution system based on visual observations -Adjustment of air distribution based on continuous or periodic monitoring.	All combustion units	-Routine & periodic adjustments & checks.

[1] EPA Guidance document "Good Combustion Practices" available at: http://www.epa.gov/ttn/atw/iccr/dirss/gcp.pdf.

11. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is included in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Paul Greywall, have reviewed the following sections of the attached application for an initial new source review permit submitted by Targa:

Emissions Data

Best Available Control Technology

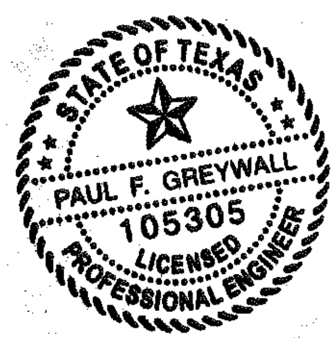
The capital cost of the project is estimated to be greater than $25,000,000.

The application for initial new source review, as referenced above, was reviewed on the 16th day of February 2012.

Signed: [signature]

Date: 2/16/2012

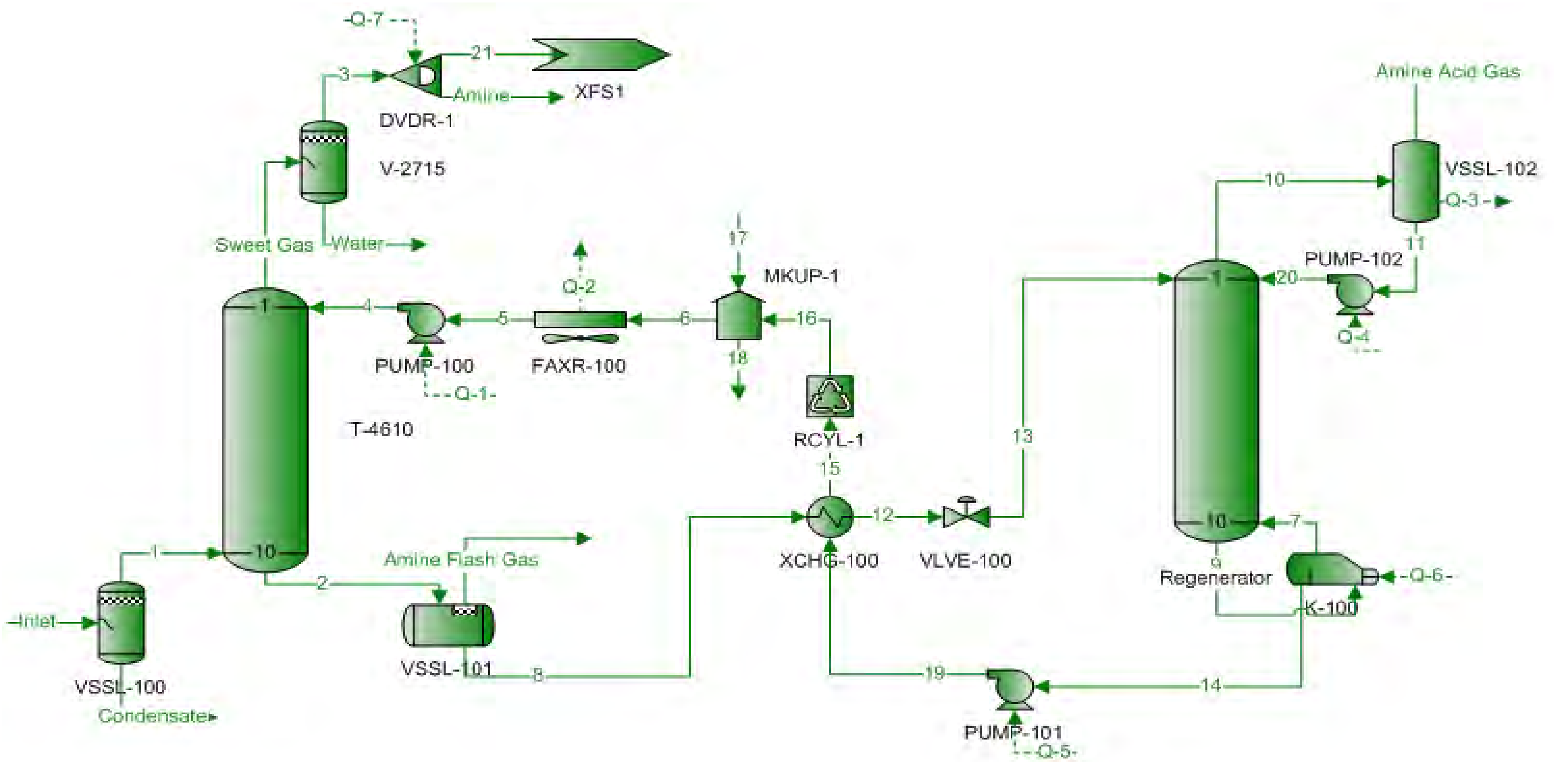
Professional Engineer Registration Number: 105305



APPENDIX A

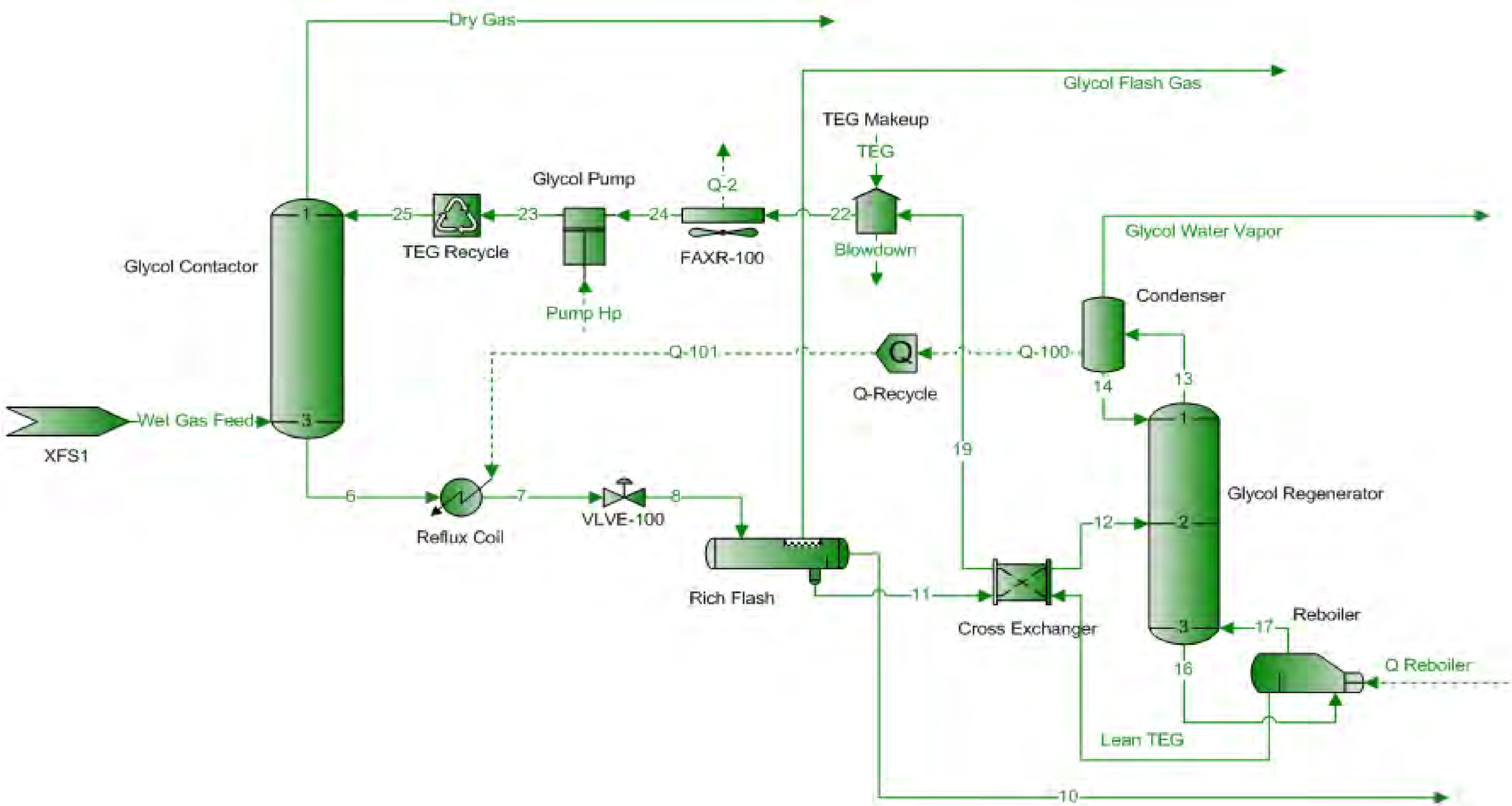
ProMax® Simulation Output

Amine Treating



Process Streams		Amine Acid Gas	Amine Flash Gas	Inlet
Composition	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	VSSL-102	VSSL-101	--
	To Block:	--	--	VSSL-100
Mole Fraction		%	%	%
Nitrogen		0.000246775	0.248362	0.803431*
Carbon Dioxide		93.8400	8.39780	2.71733*
Methane		0.255853	71.5547	79.8759*
Ethane		0.0671402	11.1537	10.0863*
Propane		0.0160832	3.17660	4.09657*
i-Butane		0.00112021	0.276918	0.522235*
n-Butane		0.00454635	0.772234	1.07181*
i-Pentane		0.000274774	0.0921720	0.287705*
n-Pentane		0.000471037	0.122217	0.298821*
n-Hexane		8.53680E-05	0.0263067	0.0906276*
MDEA		1.49914E-08	0.000476035	0*
Piperazine		5.06651E-09	4.93182E-05	0*
Water		5.79292	4.09677	0*
Benzene		0.0103754	0.0212350	0.00540761*
Cyclohexane		0.000479875	0.0245363	0.0190268*
iC7		1.88605E-05	0.0106553	0.0751057*
nC7		5.02279E-06	0.00284667	0.0211298*
Toluene		0.00859850	0.0164290	0.00500705*
iC8		3.25632E-06	0.00193688	0.0157221*
nC8		4.04565E-07	0.000188522	0.00140197*
Ethylbenzene		0.000240429	0.000524431	0.000200282*
p-Xylene		0.00149297	0.00236132	0.000901269*
Isononane		1.87456E-06	0.000580531	0.00350493*
nC9		9.20587E-07	0.000145980	0.000500705*
Decane		1.28739E-06	0.000261060	0.00140197*
Mass Flow		lb/h	lb/h	lb/h
Nitrogen		0.0437418	1.63974	4942.42*
Carbon Dioxide		26131.4	87.1036	26261.1*
Methane		25.9711	270.541	281392*
Ethane		12.7741	79.0430	66600.3*
Propane		4.48741	33.0128	39668.0*
i-Butane		0.411974	3.79331	6665.50*
n-Butane		1.67199	10.5783	13679.9*
i-Pentane		0.125439	1.56730	4558.28*
n-Pentane		0.215037	2.07819	4734.39*
n-Hexane		0.0465486	0.534286	1715.02*
MDEA		1.13034E-05	0.0133691	0*
Piperazine		2.76134E-06	0.00100118	0*
Water		660.339	17.3943	0*
Benzene		5.12801	0.390925	92.7571*
Cyclohexane		0.255540	0.486672	351.636*
iC7		0.0119580	0.251633	1652.62*
nC7		0.00318456	0.0672260	464.938*
Toluene		5.01293	0.356759	101.309*
iC8		0.00235359	0.0521436	394.376*
nC8		0.000292409	0.00507530	35.1673*
Ethylbenzene		0.161509	0.0131218	4.66926*
p-Xylene		1.00290	0.0590827	21.0117*
Isononane		0.00152126	0.0175479	98.7141*
nC9		0.000747082	0.00441258	14.1020*
Decane		0.00115901	0.00875415	43.8040*

Process Streams		Amine Acid Gas	Amine Flash Gas	Inlet
Properties	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	VSSL-102	VSSL-101	--
	To Block:	--	--	VSSL-100
Property	**Units**			
Temperature	°F	120.000	148.892	100*
Pressure	psia	29.6959	79.6959*	950*
Mole Fraction Vapor	%	100	100	100
Mole Fraction Light Liquid	%	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0
Molecular Weight	lb/lbmol	42.4327	21.5976	20.6512
Mass Density	lb/ft^3	0.204451	0.266739	3.93427
Molar Flow	lbmol/h	632.745	23.5681	21959.6
Mass Flow	lb/h	26849.1	509.013	453492
Vapor Volumetric Flow	ft^3/h	131323	1908.28	115267
Liquid Volumetric Flow	gpm	16372.7	237.916	14371.0
Std Vapor Volumetric Flow	MMSCFD	5.76280	0.214649	200*
Std Liquid Volumetric Flow	sgpm	65.5439	2.69633	2596.86
Compressibility		0.990750	0.988068	0.830248
Specific Gravity		1.46509	0.745706	0.713029
API Gravity				
Enthalpy	Btu/h	-1.04112E+08	-1.10711E+06	-8.26860E+08
Mass Enthalpy	Btu/lb	-3877.67	-2175.01	-1823.32
Mass Cp	Btu/(lb*°F)	0.215983	0.472053	0.618622
Ideal Gas CpCv Ratio		1.28013	1.24616	1.25095
Dynamic Viscosity	cP	0.0161538	0.0126621	0.0132174
Kinematic Viscosity	cSt	4.93246	2.96346	0.209730
Thermal Conductivity	Btu/(h*ft*°F)	0.0106611	0.0201292	0.0223543
Surface Tension	lbf/ft			
Net Ideal Gas Heating Value	Btu/ft^3	4.83569	949.022	1065.68
Net Liquid Heating Value	Btu/lb	-55.8135	16585.6	19529.0
Gross Ideal Gas Heating Value	Btu/ft^3	8.19673	1049.86	1176.15
Gross Liquid Heating Value	Btu/lb	-25.7551	18357.4	21558.7


Dry Gas
Glycol Flash Gas
TEG Makeup
TEG
Glycol Pump
Q-2
25
23
24
22
TEG Recycle
FAXR-100
Blowdown
Glycol Contactor
Glycol Water Vapor
Condenser
Pump Hp
Q-101
Q-100
Q-Recycle
13
14
XFS1
Wet Gas Feed
1
3
19
Glycol Regenerator
6
7
8
Reflux Coil
VLVE-100
12
2
Rich Flash
11
Cross Exchanger
Reboiler
17
16
Q Reboiler
Lean TEG
10

Process Streams		Glycol Flash Gas	Glycol Water Vapor	Wet Gas Feed
Composition	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	Rich Flash	Condenser	XFS1
	To Block:	--	--	Glycol Contactor
Mole Fraction		%	%	%
Nitrogen		0.196861	0.000358836	0.824642
Carbon Dioxide		0.0197680	0.00126829	0.00452168
Methane		63.3773	0.444557	81.9261
Ethane		18.3261	0.430090	10.3418
Propane		10.0939	0.455862	4.20217
i-Butane		1.21526	0.0660641	0.535867
n-Butane		3.06443	0.245600	1.09949
i-Pentane		0.868767	0.121134	0.295291
n-Pentane		0.989680	0.167806	0.306666
n-Hexane		0.297787	0.0871198	0.0930204
Water		1.05601	97.3598	0.217799
Triethylene Glycol		0.000432376	7.43242E-05	0
Benzene		0.0270769	0.135690	0.00522191
Cyclohexane		0.0786381	0.0700645	0.0194945
iC7		0.234987	0.102667	0.0771025
nC7		0.0652468	0.0352452	0.0216917
Toluene		0.0211680	0.183343	0.00486850
iC8		0.0469911	0.0231737	0.0161405
nC8		0.00382784	0.00355417	0.00143926
Ethylbenzene		0.000691875	0.00839197	0.000197949
p-Xylene		0.00298959	0.0377685	0.000878607
Isononane		0.00832221	0.0108131	0.00359800
nC9		0.00115892	0.00195458	0.000513911
Decane		0.00259760	0.00755507	0.00143915
Mass Flow		lb/h	lb/h	lb/h
Nitrogen		0.236827	0.00441512	4940.73
Carbon Dioxide		0.0373607	0.0245157	42.5604
Methane		43.6626	3.13241	281095
Ethane		23.6644	5.68014	66508.5
Propane		19.1144	8.82894	39630.5
i-Butane		3.03331	1.68651	6661.30
n-Butane		7.64885	6.26975	13667.7
i-Pentane		2.69177	3.83864	4556.59
n-Pentane		3.06640	5.31762	4732.10
n-Hexane		1.10203	3.29747	1714.44
Water		0.816984	770.373	839.184
Triethylene Glycol		0.00278842	0.00490233	0
Benzene		0.0908282	4.65529	87.2382
Cyclohexane		0.284211	2.58989	350.894
iC7		1.01117	4.51841	1652.36
nC7		0.280763	1.55116	464.868
Toluene		0.0837580	7.41968	95.9392
iC8		0.230513	1.16265	394.322
nC8		0.0187773	0.178317	35.1619
Ethylbenzene		0.00315438	0.391314	4.49463
p-Xylene		0.0136301	1.76113	19.9497
Isononane		0.0458372	0.609124	98.6951
nC9		0.00638313	0.110105	14.0969
Decane		0.0158718	0.472137	43.7941

Process Streams		Glycol Flash Gas	Glycol Water Vapor	Wet Gas Feed
Properties	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	Rich Flash	Condenser	XFS1
	To Block:	--	--	Glycol Contactor
Property	**Units**			
Temperature	°F	139.063	210.702	124.415
Pressure	psia	75	14.7	946.906
Mole Fraction Vapor	%	100	100	100
Mole Fraction Light Liquid	%	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0
Molecular Weight	lb/lbmol	24.9539	18.9855	19.9953
Mass Density	lb/ft^3	0.296961	0.0391252	3.51584
Molar Flow	lbmol/h	4.29443	43.9218	21387.5
Mass Flow	lb/h	107.163	833.878	427651
Vapor Volumetric Flow	ft^3/h	360.865	21313.0	121635
Liquid Volumetric Flow	gpm	44.9909	2657.21	15164.9
Std Vapor Volumetric Flow	MMSCFD	0.0391120	0.400024	194.789
Std Liquid Volumetric Flow	sgpm	0.565889	1.75786	2531.65
Compressibility		0.980851	0.991523	0.859145
Specific Gravity		0.861590	0.655518	0.690385
API Gravity				
Enthalpy	Btu/h	-154915	-4.44236E+06	-7.23070E+08
Mass Enthalpy	Btu/lb	-1445.61	-5327.36	-1690.80
Mass Cp	Btu/(lb*°F)	0.494449	0.458094	0.626242
Ideal Gas CpCv Ratio		1.19562	1.29866	1.24383
Dynamic Viscosity	cP	0.0112188	0.0125943	0.0132408
Kinematic Viscosity	cSt	2.35844	20.0953	0.235107
Thermal Conductivity	Btu/(h*ft*°F)	0.0186144	0.0154084	0.0233279
Surface Tension	lbf/ft			
Net Ideal Gas Heating Value	Btu/ft^3	1341.79	73.3448	1093.00
Net Liquid Heating Value	Btu/lb	20302.4	473.045	20689.0
Gross Ideal Gas Heating Value	Btu/ft^3	1473.24	127.985	1206.41
Gross Liquid Heating Value	Btu/lb	22301.2	1565.03	22841.2

APPENDIX B

Gas and Liquid Analyses

Inlet Gas Analysis

Component	Mole %
N2	1.0350
CO2	3.9520
H2S	0.0000
C1	77.7760
C2	9.8110
C3	4.5080
iC4	0.4910
nC4	1.2190
iC5	0.3280
nC5	0.3410
iC6	0.1800
NC6	0.1170
Benzene	0.0080
Cyclohexane	0.0250
IC7	0.1150
NC7	0.0310
Toluene	0.0080
IC8	0.0380
NC8	0.0050
E-Benzene	0.0000
m.o.p-Xylene	0.0020
IC9	0.0090
NC9	0.0010
IC10	0.0010
NC10	0.0000
I-Undecanes	0.0010
Total	100.00
Total TOC	95.02
Total VOC (NMNEHC)	7.43

file: EX0510A 200MM.xls
sheet: 200 MMscfd Ethane Recovery

11/23/2011

VALERUS

Valerus Compression Services

Houston, Texas

EXPANDER/COMPRESSOR

Client	**Targa**	P.O. Number	
Subject	**200 MMscfd Expander Plant**	By	DGH
Job No.	**26956 Ethane Recovery**	Revision	A

Tag No.	EC-0510		C-0510	
Service	EXPANDER		BOOSTER COMPRESSOR	
	Inlet	Outlet	Inlet	Outlet
Gas Composition, Mol %				
CO2	0.02%		0.01%	
N2	1.73%		1.75%	
H2S	0.00%		0.00%	
C1	87.62%		97.50%	
C2	7.86%		0.70%	
C3	2.28%		0.04%	
iC4	0.13%		0.00%	
nC4	0.28%		0.00%	
iC5	0.04%		0.00%	
nC5	0.03%		0.00%	
C6	0.01%		0.00%	
C7	0.00%		0.00%	
Flow Rate, Lbs/Hr	215,089		279,040	
Mols/Hr	11,804.46		17,051.02	
Mol Wt.	18.22		16.37	
Specific Heat, BTU/Lb-F	0.9635		0.5605	0.5758
Vapor Compressibility	0.6217	0.8139	0.9694	0.9706
k=Cp/Cv, Ideal	2.5080	1.6390	1.3380	1.3300
Flowrate, ACFM	606.50		6,411	5,520
Pressure, psia	930.0	285	265	329
Temperature, degF	-30.00	-113.10	115.0	154.4
Wt. % Liquid		16.46%		
Compression Ratio	3.26		1.24	
BHP	2310		2263	
RPM				
Efficiency, Design/Calc.%	83% / 87.0%		73% / 80.0%	
Lube Oil, gpm				
Lube Oil Pressure, psia				
Lube Oil Cooler, MBTU/Hr				
Seal Gas, SCFM	230 to 345			
Seal Gas Pressure, psia	470 to 915			
Seal Gas Temperature, degF	90 to 130 dF			
Connections, Size/Rating	8" 600#	10" 600#	18" 300#	16" 300#
Altitude, feet	950			
Ambient Temperature, degF	20 to 105 dF			
Manufacturer				
Model				

Notes:
1. Unit should be suitable for a Class 1, Group D, Div. 2 Area Classification per NEC Code.
2. Vendor to supply expander complete with lube oil system and seal gas system.
3. Vendor to include the required control panel suitable for the above operating area.

SHERRY Laboratories

Testing Today – Protecting Tomorrow®

CONDENSATE ANALYSIS REPORT NO.: 7-082106-7 (131847) **DATE:** 08/21/06

FOR: TARGA MIDSTREAM SERVICES
ATTN: ALBERT FLOURNOY
383 CR 1745
CHICO TX 76431

SAMPLE IDENTIFICATION:
COMPANY: TARGA MIDSTREAM SERVICES
FIELD: CHICO
LEASE: CHICO PLANT CONDENSATE
STA #:

SAMPLE DATA: **DATE:** 07/27/06 **BY:** R. N. WALTON
PSIG: 7 **TEMP:** 98 **DEG.F.**

REMARKS:

CYL #239

COMPONENT ANALYSIS

COMPONENT		MOL PERCENT	WT. PERCENT	LIQ VOL PERCENT
CARBON DIOXIDE	(CO_2)	0.000	0.000	0.000
METHANE	(C1)	0.010	0.000	0.000
ETHANE	(C2)	0.137	0.040	0.080
PROPANE	(C3)	1.300	0.590	0.830
ISO-BUTANE	(IC4)	0.819	0.490	0.620
N-BUTANE	(NC4)	3.515	2.090	2.560
ISO-PENTANE	(IC5)	3.499	2.580	2.960
N-PENTANE	(NC5)	5.355	3.950	4.480
HEXANES	(C6)	12.894	11.350	12.240
HEPTANES PLUS	(C7+)	72.471	78.910	76.230
TOTALS		100.000	100.000	100.000

CALCULATED VALUES	TOTAL LIQ	HEPTANES PLUS
SPECIFIC GRAVITY @ 60 DEG. F. (WATER = 1)	0.7163	0.7416
MOLECULAR WEIGHT	97.90	106.60
POUNDS/GALLON (ABSOLUTE DENSITY)	5.9721	6.1829
POUNDS/GALLON (WEIGHT IN AIR)	5.9653	6.1760
CU. FT. VAPOR/GAL. @ 15.025 PSIA, 60 DEG F	22.643	21.529

2129 WEST WILLOW SCOTT LA 70583 337-232-3568

DATE: 08/21/06

SAMPLE IDENTIFICATION

COMPANY: TARGA MIDSTREAM SERVICES

FIELD: CHICO

LEASE: CHICO PLANT CONDENSATE

STA #:

SAMPLE DATE: 07/27/06

(131847)

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
METHANE	0.0000	0.0000	0.0000
ETHANE	0.0000	0.0000	0.0000
PROPANE	0.0000	0.0000	0.0000
ISO-BUTANE	0.0000	0.0000	0.0000
N-BUTANE	0.0000	0.0000	0.0000
2,2-DIMETHYLPROPANE (NEOPENTANE)	0.0000	0.0000	0.0000
ISOPENTANE	0.0000	0.0000	0.0000
N-PENTANE	0.0000	0.0000	0.0000
2,2-DIMETHYLBUTANE (NEOHEXANE)	0.0000	0.0000	0.0000
2,3-DIMETHYLBUTANE CYCLOPENTANE	0.0000	0.0000	0.0000
2-METHYLPENTANE	0.0000	0.0000	0.0000
3-METHYLPENTANE	0.0000	0.0000	0.0000
N-HEXANE	0.0000	0.0000	0.0000
2,2-DIMETHYLPENTANE	0.0000	0.0000	0.0000
METHYLCYCLOPENTANE	4.0787	3.5036	3.3313
2,4-DIMETHYLPENTANE	0.0000	0.0000	0.0000
2,2,3-TRIMETHYLBUTANE	0.0000	0.0000	0.0000
BENZENE	0.6334	0.5034	0.4078
3,3-DIMETHYLPENTANE	0.0000	0.0000	0.0000
CYCLOHEXANE	3.7779	3.2487	2.9707
2-METHYLHEXANE	3.7852	3.8705	4.0600
2,3-DIMETHYLPENTANE	0.0000	0.0000	0.0000
1,1-DIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
3-METHYLHEXANE	3.8547	3.9455	4.0875
1,t3-DIMETHYLCYCLOPENTANE	1.7458	1.7526	1.6664

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
1,c3-DIMETHYLCYCLOPENTANE 3-ETHYLPENTANE	3.4532	3.4697	3.3373
1,t2-DIMETHYLCYCLOPENTANE 2,2,4-TRIMETHYLPENTANE	0.0000	0.0000	0.0000
N-HEPTANE	8.1505	8.3386	8.6763
METHYLCYCLOHEXANE 1,1,3-TRIMETHYLCYCLOPENTANE 2,2-DIMETHYLHEXANE	7.5631	7.7000	7.1618
1,c2-DIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2,5-DIMETHYLHEXANE	1.9314	2.2568	2.3166
2,4-DIMETHYLHEXANE 2,2,3-TRIMETHYLPENTANE ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1,t2,c4-TRIMETHYLCYCLOPENTANE 3,3-DIMETHYLHEXANE	1.1436	1.3099	1.2517
1,t2,c3-TRIMETHYLCYCLOPENTANE	0.6254	0.7173	0.6777
2,3,4-TRIMETHYLPENTANE	0.0000	0.0000	0.0000
TOLUENE	3.8707	3.6425	2.9928
2,3-DIMETHYLHEXANE	0.0000	0.0000	0.0000
1,1,2-TRIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2-METHYLHEPTANE	2.7967	3.2645	3.3313
4-METHYLHEPTANE	0.0000	0.0000	0.0000
3,4-DIMETHYLHEXANE	0.0000	0.0000	0.0000
3-METHYLHEPTANE 3-ETHYLHEXANE	2.1473	2.5101	2.5278
1,c3-DIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOPENTANE 1,c2,t4-TRIMETHYLCYCLOPENTANE	3.6540	4.1885	3.8915
1,t4-DIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
2,2,5-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1,1-DIMETHYLCYCLOHEXANE 1,methyl-t3-ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1-methyl-c3-ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1-methyl-t2-ETHYLCYCLOPENTANE 2,2,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1-methyl-1-ETHYLCYCLOPENTANE CYCLOHEPTANE	0.0000	0.0000	0.0000

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
N-OCTANE 1,t2-DIMETHYLCYCLOHEXANE	5.9948	6.9962	7.0902
UNKNOWN	0.0000	0.0000	0.0000
1,t3-DIMETHYLCYCLOHEXANE 1,c4-DIMETHYLCYCLOHEXANE 1,c2,c3-TRIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2,4,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
ISOPROPYLCYCLOPENTANE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0016	0.0015
2,2-DIMETHYLHEPTANE	0.0000	0.0000	0.0000
2,4-DIMETHYLHEPTANE 1-methyl-c2-ETHYLCYCLOPENTANE	0.0312	0.0426	0.0404
2,2,3-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1,c2-DIMETHYLCYCLOHEXANE 2,6-DIMETHYLHEPTANE	0.3087	0.3654	0.3339
N-PROPYLCYCLOPENTANE 1,c3,c5-TRIMETHYLCYCLOHEXANE	0.5638	0.6841	0.6304
2,5-DIMETHYLHEPTANE 3,5-DIMETHYLHEPTANE ETHYLCYCLOHEXANE	0.2855	0.3362	0.3072
1,1,3-TRIMETHYLCYCLOHEXANE 2,3,3-TRIMETHYLHEXANE 3,3-DIMETHYLHEPTANE	0.5022	0.6510	0.6144
1,1,4-TRIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0000	0.0000
2,3,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
ETHYLBENZENE	0.0848	0.0931	0.0762
1,t2,t4-TRIMETHYLCYCLOHEXANE	0.0000	0.0032	0.0030
1,c3,t5-TRIMETHYLCYCLOHEXANE 2,3-DIMETHYLHEPTANE	0.0000	0.0000	0.0000
M-XYLENE P-XYLENE 3,4-DIMETHYLHEPTANE	1.6531	1.7991	1.4911
2-METHYLOCTANE 4-METHYLOCTANE	1.1972	1.5735	1.5650
UNKNOWN	0.0000	0.0000	0.0000
3-METHYLOCTANE	1.1436	1.4977	1.4811

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.0000	0.0000	0.0000
1,t2,c3-TRIMETHYLCYCLOHEXANE 1,t2,c4-TRIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
O-XYLENE	0.5638	0.6100	0.4940
1,1,2-TRIMETHYLCYCLOHEXANE	0.0928	0.1215	0.1082
UNKNOWN	0.3247	0.4719	0.4543
ISOBUTYLCYCLOPENTANE	0.0000	0.0000	0.0000
N-NONANE	2.6032	3.4121	3.3869
UNKNOWN	0.0000	0.0000	0.0000
1,c2,c3-TRIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOHEXANE	0.0080	0.0126	0.0114
UNKNOWN	0.0000	0.0000	0.0000
ISOPROPYLBENZENE	0.0000	0.0008	0.0008
2,2-DIMETHYLOCTANE	0.0152	0.0229	0.0229
ISOPROPYLCYCLOHEXANE CYCLOOCTANE	0.0384	0.0434	0.0374
UNKNOWN	0.0384	0.0552	0.0503
N-BUTYLCYCLOPENTANE N-PROPYLCYCLOHEXANE	0.3711	0.4758	0.4299
3,3-DIMETHYLOCTANE	0.0000	0.0000	0.0000
UNKNOWN	0.0464	0.0631	0.0572
N-PROPYLBENZENE	0.0544	0.0655	0.0541
UNKNOWN	0.0000	0.0000	0.0000
m-ETHYLTOLUENE	0.1855	0.2304	0.1898
p-ETHYLTOLUENE 2,3-DIMETHYLOCTANE	0.2623	0.3235	0.2676
4-METHYLNONANE 5-METHYLNONANE 1,3,5-TRIMETHYLBENZENE	0.2239	0.2975	0.2615
2-METHYLNONANE	0.0000	0.0000	0.0000
3-ETHYLOCTANE	0.0000	0.0000	0.0000
O-ETHYLTOLUENE 3-METHYLNONANE	0.1239	0.1633	0.1441
UNKNOWN	0.0312	0.0442	0.0404
1,2,4-TRIMETHYLBENZENE t-BUTYLBENZENE METHYLCYCLOOCTANE	0.2855	0.3677	0.3034

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
tert-BUTYLCYCLOHEXANE	0.0000	0.0000	0.0000
ISO-BUTYLCYCLOHEXANE	0.0000	0.0000	0.0000
N-DECANE	0.4095	0.5958	0.5816
ISOBUTYLBENZENE	0.0000	0.0000	0.0000
sec-BUTYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0000	0.0000
1-METHYL-3-ISOPROPYLBENZENE	0.1080	0.1468	0.1220
1,2,3-TRIMETHYLBENZENE 1-METHYL-4-ISOPROPYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0928	0.1491	0.1441
1-METHYL-2-ISOPROPYLBENZENE	0.0312	0.0442	0.0358
UNKNOWN	0.0384	0.0671	0.0648
N-BUTYLCYCLOHEXANE	0.0232	0.0379	0.0343
UNKNOWN	0.0000	0.0000	0.0000
1,3-DIETHYLBENZENE 1-METHYL-3-PROPYLBENZENE	0.0232	0.0276	0.0229
1,2-DIETHYLBENZENE N-BUTYLBENZENE 1-METHYL-4-PROPYLBENZENE	0.0464	0.0584	0.0480
1,4-DIETHYLBENZENE	0.0616	0.0876	0.0724
1-METHYL-2-PROPYLBENZENE	0.0312	0.0473	0.0389
1,4-DIMETHYL-2-ETHYLBENZENE	0.0080	0.0087	0.0069
UNKNOWN	0.0152	0.0237	0.0229
1,2-DIMETHYL-4-ETHYLBENZENE	0.0080	0.0079	0.0069
1,3-DIMETHYL-2-ETHYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0464	0.0789	0.0762
1,2-DIMETHYL-3-ETHYLBENZENE	0.0464	0.0655	0.0526
UNKNOWN	0.0000	0.0000	0.0000
N-UNDECANE	0.2087	0.3362	0.3240
UNKNOWN	0.0544	0.0931	0.0884
1,2,4,5-TETRAMETHYLBENZENE	0.0152	0.0166	0.0130
1,2,3,5-TETRAMETHYLBENZENE	0.0000	0.0008	0.0008
UNKNOWN	0.0152	0.0276	0.0267
1,2,3,4-TETRAMETHYLBENZENE CYCLODECANE	0.0080	0.0126	0.0107

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.1007	0.1768	0.1685
NAPHTHALENE	0.0000	0.0047	0.0030
N-DODECANE	0.1623	0.2864	0.2721
ISOTRIDECANES PLUS	0.6718	1.4614	1.3554
TOTALS	72.4710	78.9100	76.2300

TOTAL HEXANES	=	0.0000	0.0000	0.0000
TOTAL HEPTANES	=	29.4794	28.6326	28.5373
TOTAL OCTANES	=	29.7270	32.5858	31.2414
TOTAL NONANES	=	9.3546	11.6630	10.9876
TOTAL DECANES PLUS	=	3.9100	6.0286	5.4637

DATE: 08/21/06

SAMPLE IDENTIFICATION

COMPANY: TARGA MIDSTREAM SERVICES
FIELD: CHICO
LEASE: CHICO PLANT CONDENSATE
STA #:

SAMPLE DATE: 07/27/06
(131847)

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
METHANE	0.000	0.000	0.000
ETHANE	0.000	0.000	0.000
PROPANE	0.000	0.000	0.000
ISO-BUTANE	0.000	0.000	0.000
N-BUTANE	0.000	0.000	0.000
2,2-DIMETHYLPROPANE (NEOPENTANE)	0.000	0.000	0.000
ISOPENTANE	0.000	0.000	0.000
N-PENTANE	0.000	0.000	0.000
2,2-DIMETHYLBUTANE (NEOHEXANE)	0.000	0.000	0.000
2,3-DIMETHYLBUTANE CYCLOPENTANE	0.000	0.000	0.000
2-METHYLPENTANE	0.000	0.000	0.000
3-METHYLPENTANE	0.000	0.000	0.000
N-HEXANE	0.000	0.000	0.000
2,2-DIMETHYLPENTANE	0.000	0.000	0.000
METHYLCYCLOPENTANE	5.628	4.440	4.370
2,4-DIMETHYLPENTANE	0.000	0.000	0.000
2,2,3-TRIMETHYLBUTANE	0.000	0.000	0.000
BENZENE	0.874	0.638	0.535
3,3-DIMETHYLPENTANE	0.000	0.000	0.000
CYCLOHEXANE	5.213	4.117	3.897
2-METHYLHEXANE	5.223	4.905	5.326
2,3-DIMETHYLPENTANE	0.000	0.000	0.000
1,1-DIMETHYLCYCLOPENTANE	0.000	0.000	0.000
3-METHYLHEXANE	5.319	5.000	5.362
1,t3-DIMETHYLCYCLOPENTANE	2.409	2.221	2.186

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
1,c3-DIMETHYLCYCLOPENTANE 3-ETHYLPENTANE	4.765	4.397	4.378
1,t2-DIMETHYLCYCLOPENTANE 2,2,4-TRIMETHYLPENTANE	0.000	0.000	0.000
N-HEPTANE	11.247	10.567	11.382
METHYLCYCLOHEXANE 1,1,3-TRIMETHYLCYCLOPENTANE 2,2-DIMETHYLHEXANE	10.436	9.758	9.395
1,c2-DIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2,5-DIMETHYLHEXANE	2.665	2.860	3.039
2,4-DIMETHYLHEXANE 2,2,3-TRIMETHYLPENTANE ETHYLCYCLOPENTANE	0.000	0.000	0.000
1,t2,c4-TRIMETHYLCYCLOPENTANE 3,3-DIMETHYLHEXANE	1.578	1.660	1.642
1,t2,c3-TRIMETHYLCYCLOPENTANE	0.863	0.909	0.889
2,3,4-TRIMETHYLPENTANE	0.000	0.000	0.000
TOLUENE	5.341	4.616	3.926
2,3-DIMETHYLHEXANE	0.000	0.000	0.000
1,1,2-TRIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2-METHYLHEPTANE	3.859	4.137	4.370
4-METHYLHEPTANE	0.000	0.000	0.000
3,4-DIMETHYLHEXANE	0.000	0.000	0.000
3-METHYLHEPTANE 3-ETHYLHEXANE	2.963	3.181	3.316
1,c3-DIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOPENTANE 1,c2,t4-TRIMETHYLCYCLOPENTANE	5.042	5.308	5.105
1,t4-DIMETHYLCYCLOHEXANE	0.000	0.000	0.000
2,2,5-TRIMETHYLHEXANE	0.000	0.000	0.000
1,1-DIMETHYLCYCLOHEXANE 1,methyl-t3-ETHYLCYCLOPENTANE	0.000	0.000	0.000
1-methyl-c3-ETHYLCYCLOPENTANE	0.000	0.000	0.000
1-methyl-t2-ETHYLCYCLOPENTANE 2,2,4-TRIMETHYLHEXANE	0.000	0.000	0.000
1-methyl-1-ETHYLCYCLOPENTANE CYCLOHEPTANE	0.000	0.000	0.000

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
N-OCTANE 1,t2-DIMETHYLCYCLOHEXANE	8.272	8.866	9.301
UNKNOWN	0.000	0.000	0.000
1,t3-DIMETHYLCYCLOHEXANE 1,c4-DIMETHYLCYCLOHEXANE 1,c2,c3-TRIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2,4,4-TRIMETHYLHEXANE	0.000	0.000	0.000
ISOPROPYLCYCLOPENTANE	0.000	0.000	0.000
UNKNOWN	0.000	0.002	0.002
2,2-DIMETHYLHEPTANE	0.000	0.000	0.000
2,4-DIMETHYLHEPTANE 1-methyl-c2-ETHYLCYCLOPENTANE	0.043	0.054	0.053
2,2,3-TRIMETHYLHEXANE	0.000	0.000	0.000
1,c2-DIMETHYLCYCLOHEXANE 2,6-DIMETHYLHEPTANE	0.426	0.463	0.438
N-PROPYLCYCLOPENTANE 1,c3,c5-TRIMETHYLCYCLOHEXANE	0.778	0.867	0.827
2,5-DIMETHYLHEPTANE 3,5-DIMETHYLHEPTANE ETHYLCYCLOHEXANE	0.394	0.426	0.403
1,1,3-TRIMETHYLCYCLOHEXANE 2,3,3-TRIMETHYLHEXANE 3,3-DIMETHYLHEPTANE	0.693	0.825	0.806
1,1,4-TRIMETHYLCYCLOHEXANE	0.000	0.000	0.000
UNKNOWN	0.000	0.000	0.000
2,3,4-TRIMETHYLHEXANE	0.000	0.000	0.000
ETHYLBENZENE	0.117	0.118	0.100
1,t2,t4-TRIMETHYLCYCLOHEXANE	0.000	0.004	0.004
1,c3,t5-TRIMETHYLCYCLOHEXANE 2,3-DIMETHYLHEPTANE	0.000	0.000	0.000
M-XYLENE P-XYLENE 3,4-DIMETHYLHEPTANE	2.281	2.280	1.956
2-METHYLOCTANE 4-METHYLOCTANE	1.652	1.994	2.053
UNKNOWN	0.000	0.000	0.000
3-METHYLOCTANE	1.578	1.898	1.943

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.000	0.000	0.000
1,t2,c3-TRIMETHYLCYCLOHEXANE 1,t2,c4-TRIMETHYLCYCLOHEXANE	0.000	0.000	0.000
O-XYLENE	0.778	0.773	0.648
1,1,2-TRIMETHYLCYCLOHEXANE	0.128	0.154	0.142
UNKNOWN	0.448	0.598	0.596
ISOBUTYLCYCLOPENTANE	0.000	0.000	0.000
N-NONANE	3.592	4.324	4.443
UNKNOWN	0.000	0.000	0.000
1,c2,c3-TRIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOHEXANE	0.011	0.016	0.015
UNKNOWN	0.000	0.000	0.000
ISOPROPYLBENZENE	0.000	0.001	0.001
2,2-DIMETHYLOCTANE	0.021	0.029	0.030
ISOPROPYLCYCLOHEXANE CYCLOOCTANE	0.053	0.055	0.049
UNKNOWN	0.053	0.070	0.066
N-BUTYLCYCLOPENTANE N-PROPYLCYCLOHEXANE	0.512	0.603	0.564
3,3-DIMETHYLOCTANE	0.000	0.000	0.000
UNKNOWN	0.064	0.080	0.075
N-PROPYLBENZENE	0.075	0.083	0.071
UNKNOWN	0.000	0.000	0.000
m-ETHYLTOLUENE	0.256	0.292	0.249
p-ETHYLTOLUENE 2,3-DIMETHYLOCTANE	0.362	0.410	0.351
4-METHYLNONANE 5-METHYLNONANE 1,3,5-TRIMETHYLBENZENE	0.309	0.377	0.343
2-METHYLNONANE	0.000	0.000	0.000
3-ETHYLOCTANE	0.000	0.000	0.000
O-ETHYLTOLUENE 3-METHYLNONANE	0.171	0.207	0.189
UNKNOWN	0.043	0.056	0.053
1,2,4-TRIMETHYLBENZENE t-BUTYLBENZENE METHYLCYCLOOCTANE	0.394	0.466	0.398

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
tert-BUTYLCYCLOHEXANE	0.000	0.000	0.000
ISO-BUTYLCYCLOHEXANE	0.000	0.000	0.000
N-DECANE	0.565	0.755	0.763
ISOBUTYLBENZENE	0.000	0.000	0.000
sec-BUTYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.000	0.000	0.000
1-METHYL-3-ISOPROPYLBENZENE	0.149	0.186	0.160
1,2,3-TRIMETHYLBENZENE 1-METHYL-4-ISOPROPYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.128	0.189	0.189
1-METHYL-2-ISOPROPYLBENZENE	0.043	0.056	0.047
UNKNOWN	0.053	0.085	0.085
N-BUTYLCYCLOHEXANE	0.032	0.048	0.045
UNKNOWN	0.000	0.000	0.000
1,3-DIETHYLBENZENE 1-METHYL-3-PROPYLBENZENE	0.032	0.035	0.030
1,2-DIETHYLBENZENE N-BUTYLBENZENE 1-METHYL-4-PROPYLBENZENE	0.064	0.074	0.063
1,4-DIETHYLBENZENE	0.085	0.111	0.095
1-METHYL-2-PROPYLBENZENE	0.043	0.060	0.051
1,4-DIMETHYL-2-ETHYLBENZENE	0.011	0.011	0.009
UNKNOWN	0.021	0.030	0.030
1,2-DIMETHYL-4-ETHYLBENZENE	0.011	0.010	0.009
1,3-DIMETHYL-2-ETHYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.064	0.100	0.100
1,2-DIMETHYL-3-ETHYLBENZENE	0.064	0.083	0.069
UNKNOWN	0.000	0.000	0.000
N-UNDECANE	0.288	0.426	0.425
UNKNOWN	0.075	0.118	0.116
1,2,4,5-TETRAMETHYLBENZENE	0.021	0.021	0.017
1,2,3,5-TETRAMETHYLBENZENE	0.000	0.001	0.001
UNKNOWN	0.021	0.035	0.035
1,2,3,4-TETRAMETHYLBENZENE CYCLODECANE	0.011	0.016	0.014

CAPILLARY ANALYSIS
HEAVY END FRACTION

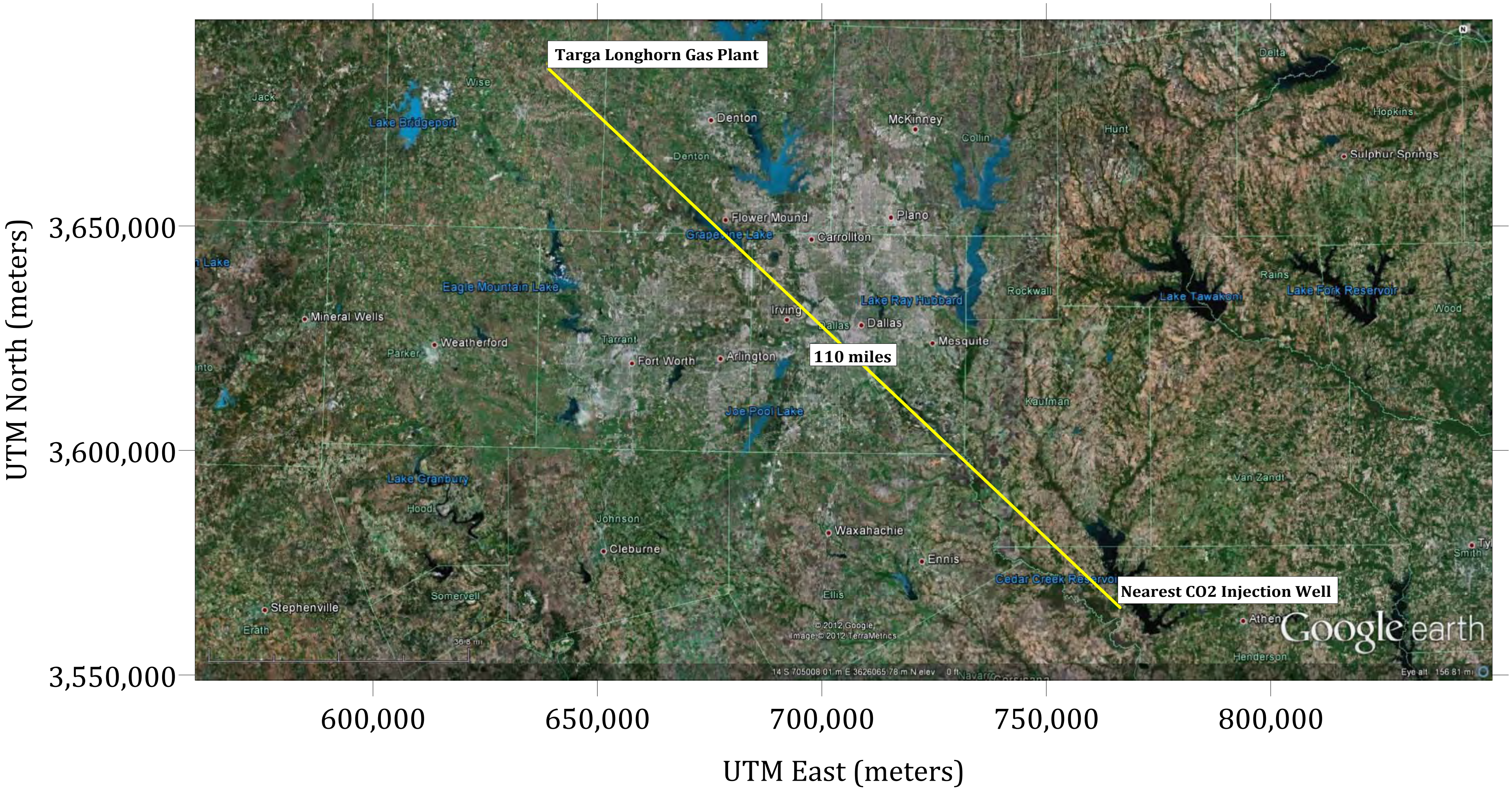
COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.139	0.224	0.221
NAPHTHALENE	0.000	0.006	0.004
N-DODECANE	0.224	0.363	0.357
ISOTRIDECANES PLUS	0.927	1.852	1.778
TOTALS	100.000	100.000	100.000

SPECIFIC GRAVITY @ 60 DEG. F. (WATER = 1)	0.7416
MOLECULAR WEIGHT	106.60
POUNDS/GALLON (ABSOLUTE DENSITY)	6.1829
POUNDS/GALLON (WEIGHT IN AIR)	6.1760
CU. FT. VAPOR/GAL @ 14.696 PSIA & 60 DEG. F.	22.011
CU. FT. VAPOR/GAL @ 15.025 PSIA & 60 DEG. F.	21.529
BTU/CU.FT. @ 14.696 PSIA, DRY	5706.8
BTU/CU.FT. @ 15.025 PSIA, DRY	5834.6
BTU/GALLON	125612
BTU/POUND	20316
SPECIFIC GRAVITY AS VAPOR	3.6811
COMPRESSIBILITY FACTOR	0.8084
SUMMATION FACTOR	0.1142

APPENDIX C

Map of Nearest CO_2 Injection Well

Targa Midstream Services
CCS Pipeline Distance Map



Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

APPENDIX D

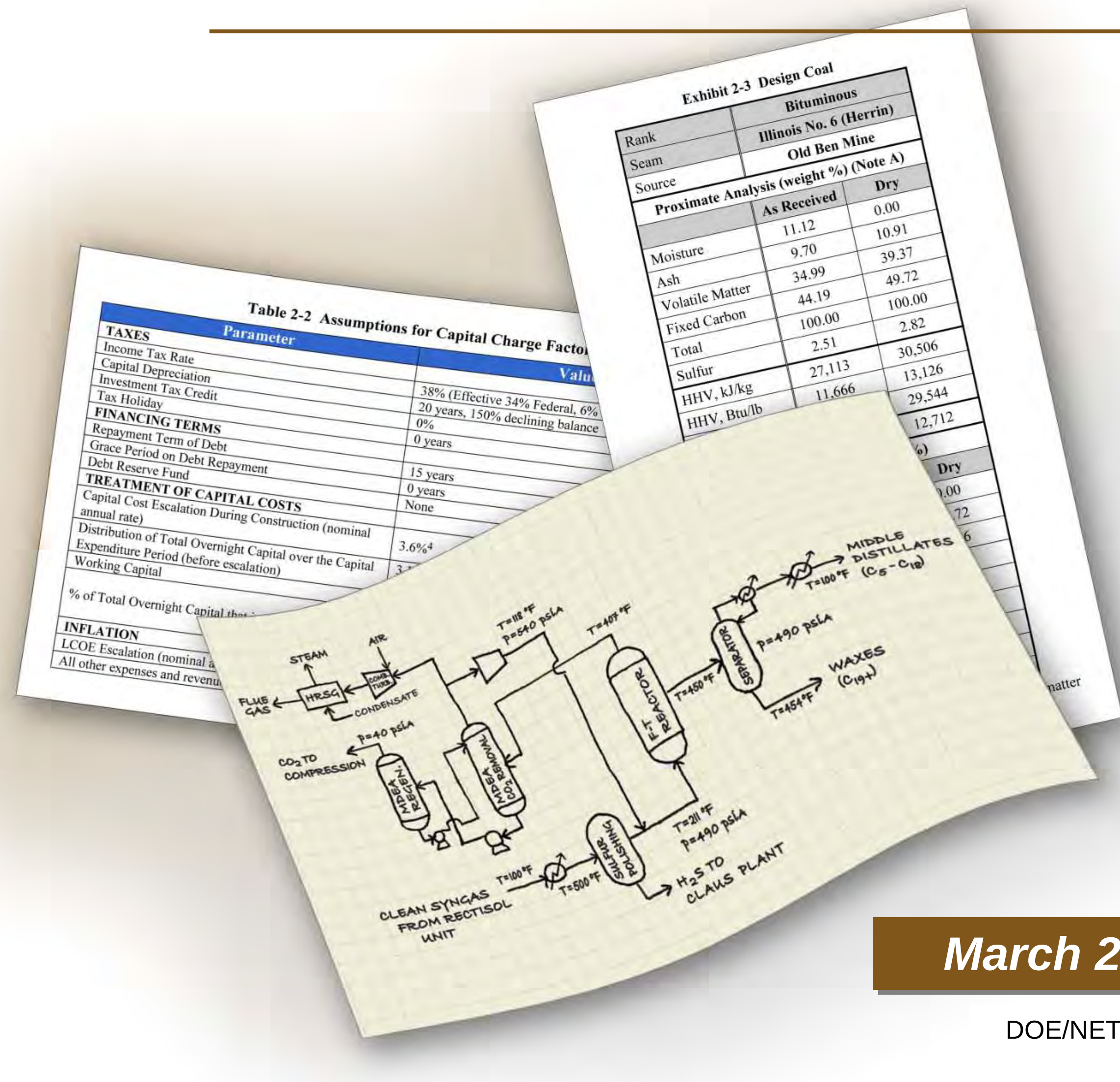
NETL Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs DOE/NETL-2010/1447

the ENERGY lab

NETL

QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES

Estimating Carbon Dioxide Transport and Storage Costs



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NATIONAL ENERGY TECHNOLOGY LABORATORY

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Quality Guidelines for Energy Systems Studies
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Background

This paper explores the costs associated with geologic sequestration of carbon dioxide (CO_2). This cost is often cited at the flat figure of $5-10 per short ton of CO_2 removed, but estimates can vary with values as high as $23 per short ton having been published recently [1, 2, 3]. The variability of these costs is due in part to the wide range of transportation and storage options available for CO_2 sequestration, but may also relate to the dramatic rise of construction and material costs in the United States which has occurred over the last several years. This paper examines the transportation of CO_2 via pipeline to, and storage of that CO_2 in, a geologic formation representative of those identified in North America as having storage potential based on data available from the literature.

Approach

Geologic sequestration costs were assessed based on the pipeline transport and injection of super-critical CO_2 into a geologic reservoir representative of those identified in North America as having storage potential. High pressure (2,200 psig) CO_2 is provided by the power plant or energy conversion facility and the cost and energy requirements of compression are assumed by that entity. CO_2 is in a super-critical state at this pressure which is desirable for transportation and storage purposes.

CO_2 exits the pipeline terminus at a pressure of 1,200 psig, and the pipeline diameter was sized for this to be achieved without the need for recompression stages along the pipeline length. This exit pressure specification: (1) ensures that CO_2 remains in a supercritical state throughout the length of the pipeline regardless of potential pressure drops due to pipeline elevation change[1]; (2) is equivalent to the reservoir pressure – exceeding it after hydrostatic head is accounted for – alleviating the need for recompression at the storage site; and (3) minimizes the pipeline diameter required, and in turn, transport capital cost.

The required pipeline diameter was calculated iteratively by determining the diameter required to achieve a 1,000 psig pressure drop (2,200 psig inlet, 1,200 psig outlet) over the specified pipeline distance, and rounding up to the nearest even sized pipe diameter. The pipeline was sized based on the CO_2 output produced by the power plant when it is operating at full capacity (100% utilization factor) rather than the average capacity.

The storage site evaluated is a saline formation at a depth of 4,055 feet (1,236 meters) with a permeability of 22 md and down-hole pressure of 1,220 psig (8.4 MPa) [4].[2] This is considered an average storage site and requires roughly one injection well for each 10,300 short tons of CO_2 injected per day [4]. An overview of the geologic formation characteristics are shown in Table 1.

Table 1: Deep, Saline Formation Specification [4]

Parameter	Units	Average Case
Pressure	MPa (psi)	8.4 (1,220)
Thickness	m (ft)	161 (530)
Depth	m (ft)	1,236 (4,055)
Permeability	Md	22
Pipeline Distance	km (miles)	80 (50)
Injection Rate per Well	tonne (short ton) CO_2/day	9,360 (10,320)

[1] Changes in pipeline elevation can result in pipeline pressure reductions due to head losses, temperature variations or other factors. Therefore a 10% safety margin is maintained to ensure the CO_2 supercritical pressure of 1,070 psig is exceeded at all times.
[2] "md", or millidarcy, is a measure of permeability defined as 10^{-12} Darcy.

Cost Sources & Methodology

The cost metrics utilized in this study provide a best estimate of T, S, & M costs for a “typical” sequestration project, and may vary significantly based on variables such as terrain to be crossed by the pipeline, reservoir characteristics, and number of land owners from which sub-surface rights must be acquired. Raw capital and operating costs are derived from detailed cost metrics found in the literature, escalated to June 2007-year dollars using appropriate price indices. These costs were then verified against values quoted by any industrial sources available. Where regulatory uncertainty exists or costs are undefined, such as liability costs and the acquisition of underground pore volume, analogous existing policies were used for representative cost scenarios.

The following sections describe the sources and methodology used for each metric.

Cost Levelization and Sensitivity Cases

Capital costs were levelized over a 30-year period and include both process and project contingency factors. Operating costs were similarly levelized over a 30-year period and a sensitivity analysis was performed to determine the effects of different pipeline lengths on overall and avoided costs as well as the distribution of transport versus storage costs.

In several areas, such as Pore Volume Acquisition, Monitoring, and Liability, cost outlays occur over a longer time period, up to 100 years. In these cases a capital fund is established based on the net present value of the cost outlay, and this fund is then levelized as described in the previous paragraph.

Following the determination of cost metrics, a range of CO_2 sequestration rates and transport distances were assessed to determine cost sensitivity to these parameters. Costs were also assessed in terms of both removed and avoided emissions cost, which requires power plant specific information such as plant efficiency, capacity factor, and emission rates. This paper presents avoided and removed emission costs for both Pulverized Coal (PC) and Integrated Gasification Combined Cycle (IGCC) cases using data from Cases 11 & 12 (Supercritical PC with and without CO_2 Capture) and Cases 1 & 2 (GEE Gasifier with and without CO_2 Capture) from the *Bituminous Baseline Study* [5].

Transport Costs

CO_2 transport costs are broken down into three categories: pipeline costs, related capital expenditures, and O&M costs.

Pipeline costs are derived from data published in the Oil and Gas Journal’s (O&GJ) annual Pipeline Economics Report for existing natural gas, oil, and petroleum pipeline project costs from 1991 to 2003. These costs are expected to be analogous to the cost of building a CO_2 pipeline, as noted in various studies [4, 6, 7]. The University of California performed a regression analysis to generate the following cost curves from the O&GJ data: (1) Pipeline Materials, (2) Direct Labor, (3) Indirect Costs[3], and (4) Right-of-way acquisition, with each represented as a function of pipeline length and diameter [7].

Related capital expenditures were based on the findings of a previous study funded by DOE/NETL, *Carbon Dioxide Sequestration in Saline Formations – Engineering and Economic Assessment* [6]. This study utilized a similar basis for pipeline costs (Oil and Gas Journal Pipeline cost data up to the year 2000) but added a CO_2 surge tank and pipeline control system to the project.

Transport O&M costs were assessed using metrics published in a second DOE/NETL sponsored report entitled *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. This study was chosen due to the reporting of O&M costs in terms of pipeline length, whereas the other studies mentioned above either (a)

[3] Indirect costs are inclusive of surveying, engineering, supervision, contingencies, allowances for funds used during construction, administration and overheads, and regulatory filing fees.

do not report operating costs, or (b) report them in absolute terms for one pipeline, as opposed to as a length- or diameter-based metric.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Volume Acquisition. With the exception of Pore Volume Acquisition, all of the costs were obtained from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. These costs include all of the costs associated with determining, developing, and maintaining a CO_2 storage location, including site evaluation, well drilling, and the capital equipment required for distributing and injecting CO_2.

Pore Volume Acquisition costs are the costs associated with acquiring rights to use the sub-surface area where the CO_2 will be stored, i.e. the pore space in the geologic formation. These costs were based on recent research by Carnegie Mellon University which examined existing sub-surface rights acquisition as it pertains to natural gas storage [8]. The regulatory uncertainty in this area combined with unknowns regarding the number and type (private or government) of property owners requires a number of "best engineering judgment" decisions to be made, as documented below under Cost Metrics.

Liability Protection

Liability Protection addresses the fact that if damages are caused by injection and long-term storage of CO_2, the injecting party may bear financial liability. Several types of liability protection schemas have been suggested for CO_2 storage, including Bonding, Insurance, and Federal Compensation Systems combined with either tort law (as with the Trans-Alaska Pipeline Fund), or with damage caps and preemption, as is used for nuclear energy under the Price Anderson Act [9].

At present, a specific liability regime has yet to be dictated either at a Federal or (to our knowledge) State level. However, certain state governments have enacted legislation which assigns liability to the injecting party, either in perpetuity (Wyoming) or until ten years after the cessation of injection operations, pending reservoir integrity certification, at which time liability is turned over to the state (North Dakota and Louisiana) [10, 11, 12]. In the case of Louisiana, a trust fund of five million dollars is established for each injector over the first ten years (120 months) of injection operations. This fund is then used by the state for CO_2 monitoring and, in the event of an at-fault incident, damage payments.

This study assumes that a bond must be purchased before injection operations are permitted in order to establish the ability and good will of an injector to address damages where they are deemed liable. A figure of five million dollars was used for the bond based on the Louisiana fund level. This Bond level may be conservative, in that the Louisiana fund covers both liability and monitoring, but that fund also pertains to a certified reservoir where injection operations have ceased, having a reduced risk compared to active operations. This cost may be updated as more specific liability regimes are instituted at the Federal or State levels. The Bond cost was not escalated.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Cost Metrics

The following sections detail the Transport, Storage, Monitoring, and Liability cost metrics used to determine CO_2 sequestration costs for the deep, saline formation described above. The cost escalation indices utilized to bring these metrics to June-2007 year dollars are also described below.

Transport Costs

The regression analysis performed by the University of California breaks down pipeline costs into four categories: (1) Materials, (2) Labor, (3) Miscellaneous, and (4) Right of Way. The Miscellaneous category is inclusive of costs such as surveying, engineering, supervision, contingencies, allowances, overhead, and filing fees [7]. These cost categories are reported individually as a function of pipeline diameter (in inches) and length (in miles) in Table 2 [7].

The escalated CO_2 surge tank and pipeline control system capital costs, as well as the Fixed O&M costs (as a function of pipeline length) are also listed in Table 2. Fixed O&M Costs are reported in terms of dollars per miles of pipeline per year.

Storage Costs

Storage costs were broken down into five categories: (1) Site Screening and Evaluation, (2) Injection Wells, (3) Injection Equipment, (4) O&M Costs, and (5) Pore Space Acquisition. Additionally, the cost of Liability Protection is also listed here for the sake of simplicity. Several storage costs are evaluated as flat fees, including Site Screening & Evaluation and the Liability Bond required for sequestration to take place.

As mentioned in the methodology section above, the site screening and evaluation figure of $4.7 million dollars is derived from *Economic Evaluation of CO_2 Storage and Sink Enhancement Options* [4]. Some sources in

Table 2: Pipeline Cost Breakdown [4, 6, 7]

Cost Type	Units	Cost
Pipeline Costs		
Materials	$ *Diameter (inches), Length (miles)*	$\$64,632 + \$1.85 \times L \times (330.5 \times D^2 + 686.7 \times D + 26,960)$
Labor	$ *Diameter (inches), Length (miles)*	$\$341,627 + \$1.85 \times L \times (343.2 \times D^2 + 2,074 \times D + 170,013)$
Miscellaneous	$ *Diameter (inches), Length (miles)*	$\$150,166 + \$1.58 \times L \times (8,417 \times D + 7,234)$
Right of Way	$ *Diameter (inches), Length (miles)*	$\$48,037 + \$1.20 \times L \times (577 \times D + 29,788)$
Other Capital		
CO_2 Surge Tank	$	$1,150,636
Pipeline Control System	$	$110,632
O&M		
Fixed O&M	$/mile/year	$8,632

industry, however, have quoted significantly higher costs for site screening and evaluation, on the magnitude of $100 to $120 million dollars. The higher cost may be reflective of a different criteria utilized in assessing costs, such as a different reservoir size – the reservoir assessed in the higher cost case could be large enough to serve 5 to 7 different injection projects – or uncertainty regarding the success rate in finding a suitable reservoir. Future analyses will examine the sensitivity of overall T, S, and M costs to higher site evaluation costs.

Pore Space Acquisition costs are based on acquiring long-term (100-year) lease rights and paying annual rent to land-owners once the CO_2 plume has reached their property. Rights are acquired by paying a one-time $500 fee to land-owners before injection begins, as per CMU's design criteria [8]. When the CO_2 plume enters into the area owned by that owner (as determined by annual monitoring), the injector begins paying an annual "rent" of $100 per acre to that owner for the period of up to 100 years from plant start-up [8]. A 3% annual escalation rate is assumed for rental rate over the 100-year rental period [8]. Similar to the CMU study, this study assumes that the plume area will cover rights need to be acquired from 120 landowners, however, a sensitivity analysis found that the overall acquisition costs were not significantly affected by this: increasing the

Table 3: Geologic Storage Costs [4, 8, 11]

Cost Type	Units	Cost
Capital		
Site Screening and Evaluation	$	$4,738,488
Injection Wells	\$/injection well *(see formula)*[1,2,3]	$\$240{,}714 \times e^{0.0008 \times well-depth}$
Injection Equipment	\$/injection well *(see formula)*[2]	$\$94{,}029 \times \left(\frac{7{,}389}{280 \times \#of\ injection\ wells} \right)^{0.5}$
Liability Bond	$	$5,000,000
Declining Capital Funds		
Pore Space Acquisition	\$/short ton CO_2	\$0.334/short ton CO_2
O&M		
Normal Daily Expenses (Fixed O&M)	\$/injection well	$11,566
Consumables (Variable O&M)	\$/yr/short ton CO_2/day	$2,995
Surface Maintenance (Fixed O&M)	*see formula*	$\$23{,}478 \times \left(\frac{7{,}389}{280 \times \#of\ injection\ wells} \right)^{0.5}$
Subsurface Maintenance (Fixed O&M)	\$/ft-depth/inject. well	$7.08

[1]The units for the "well depth" term in the formula are meters of depth.
[2]The formulas at right describe the cost per injection well and in each case the number of injection wells should be multiplied the formula in order to determine the overall capital cost.
[3]The injection well cost is $508,652 per injection well for the 1,236 meter deep geologic reservoir assessed here.

number of owners to 120,000 resulted in a 110% increase in costs and a 1% increase in the overall LCOE of the plant [8]. However, this assumption will be revisited in future work.

To ensure that Pore Space Acquisition costs are met after injection ceases, a sinking capital fund is set up to pay for these costs by determining the present value of the costs over the 100-year period (30 years of injection followed by 70 additional years), assuming a 10% discount rate. The size of this fund – as described in Table 3 – is determined by estimating the final size of the underground CO_2 plume, based on both the total amount of CO_2 injected over the plant lifetime and the reservoir characteristics described in Table 1. After injection, the CO_2 plume is assumed to grow by 1% per year [9].

The remaining capital costs are based on the number of injection wells required, which has been calculated to be one injection well for every 10,320 short tons of CO_2 injected per day. O&M costs are based on the number of injection wells, the CO_2 injection rates, and injection well depth.

Monitoring Costs

Monitoring costs were evaluated based on the methodology set forth in the IEA Greenhouse Gas R&D Programme's *Overview of Monitoring Projects for Geologic Storage Projects* report [13]. In this scenario, operational monitoring of the CO_2 plume occurs over thirty years (during plant operation) and closure monitoring occurs for the following fifty years (for a total of eighty years). Monitoring is via electromagnetic (EM) survey, gravity survey, and periodic seismic survey, EM and gravity surveys are ongoing while seismic survey occurs in years 1, 2, 5, 10, 15, 20, 25, and 30 during the operational period, then in years 40, 50, 60, 70, and 80 after injection ceases.

Operational and closure monitoring costs are assumed to be proportional to the plume size plus a fixed cost, with closure monitoring costs evaluated at half the value of the operational costs. The CO_2 plume is assumed to grow from 18 square kilometers (km^2) after the first year to 310 km^2 in after the 30th (and final) year of injection. The plume grows by 1% per year thereafter, to a size of 510 km^2 after the 80th year [9].The present value of the life-cycle costs is assessed at a 10% discount rate and a capital fund is set up to pay for these costs over the eighty year monitoring cycle. The present value of the capital fund is equivalent to $0.377 per short ton of CO_2 to be injected over the operational lifetime of the plant.

Cost Escalation

Four different cost escalation indices were utilized to escalate costs from the year-dollars they were originally reported in, to June 2007-year dollars. These are the Chemical Engineering Plant Cost Index (CEPI), U.S. Bureau of Labor Statistics (BLS) Producer Price Indices (PPI), Handy-Whitman Index of Public Utility Costs (HWI), and the Gross-Domestic Product (GDP) Chain-type Price Index [14, 15, 16].

Table 4 details which price index was used to escalate each cost metric, as well as the year-dollars the cost was originally reported in. Note that this reporting year is likely to be different that the year the cost estimate is from.

Cost Comparisons

The capital cost metrics used in this study result in a pipeline cost ranging from $65,000 to $91,000/inch-Diameter/mile for pipeline lengths of 250 and 10 miles (respectively) and 3 to 4 million metric tonnes of CO_2 sequestered per year. When project and process contingencies of 30% and 20% (respectively) are taken into account, this range increases to $97,000 to $137,000/inch-Diameter/mile. These costs were compared to contemporary pipeline costs quoted by industry experts such as Kinder-Morgan and Denbury Resources for verification purposes. Table 5 details typical rule-of-thumb costs for various terrains and scenarios as quoted by a representative of Kinder-Morgan at the Spring Coal Fleet Meeting in 2009. As shown, the base NETL cost metric falls midway between the costs quoted for “Flat, Dry” terrain ($50,000/inch-Diameter/mile) and “High Population” or “Marsh, Wetland” terrain ($100,000/inch-Diameter/mile), although the metric is closer to the “High Population” or “Marsh, Wetland” when contingencies are taken into account [17]. These costs were stated to be inclusive of right-of-way (ROW) costs.

Table 4: Summary of Cost Escalation Methodology

Cost Metric	Year-$	Index Utilized
Transport Costs		
Pipeline Materials	2000	HWI: Steel Distribution Pipe
Direct Labor (Pipeline)	2000	HWI: Steel Distribution Pipe
Indirect Costs (Pipeline)	2000	BLS: Support Activities for Oil & Gas Operations
Right-of-Way (Pipeline)	2000	GDP: Chain-type Price Index
CO_2 Surge Tank	2000	CEPI: Heat Exchangers & Tanks
Pipeline Control System	2000	CEPI: Process Instruments
Pipeline O&M (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Storage Costs		
Site Screening/Evaluation	1999	BLS: Drilling Oil & Gas Wells
Injection Wells	1999	BLS: Drilling Oil & Gas Wells
Injection Equipment	1999	HWI: Steel Distribution Pipe
Liability Bond	2008	n/a
Pore Space Acquisition	2008	GDP: Chain-type Price Index
Normal Daily Expenses (Fixed)	1999	BLS: Support Activities for Oil & Gas Operations
Consumables (Variable)	1999	BLS: Support Activities for Oil & Gas Operations
Surface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Subsurface Maintenance	1999	BLS: Support Activities for Oil & Gas Operations
Monitoring		
Monitoring	2004	BLS: Support Activities for Oil & Gas Operations

Ronald T. Evans of Denbury Resources, Inc. provided a similar outlook, citing pipeline costs as ranging from $55,000/inch-Diameter/mile for a project completed in 2007, $80,000/inch-Diameter/mile for a recently completed pipeline in the Gulf Region (no wetlands or swamps), and $100,000/inch-Diameter/mile for a currently planned pipeline, with route obstacles and terrain issues cited as the reason for the inflated cost of that pipeline [18, 19]. Mr. Evans qualified these figures as escalated due to recent spikes in construction and material costs, quoting pipeline project costs of $30,000/inch-Diameter-mile as recent as 2006 [18, 19].

A second pipeline capital cost comparison was made with metrics published within the 2008 IEA report entitled *CO_2 Capture and Storage: A key carbon abatement option*. This report cites pipeline costs ranging from $22,000/inch-Diameter/mile to $49,000/inch-Diameter/mile (once escalated to December-2006 dollars), between 25% and 66% less than the lowest NETL metric of $65,000/inch-Diameter/mile [20].

The IEA report also presents two sets of flat figure geologic storage costs. The first figure is based on a 2005 Intergovernmental Panel on Climate Change report is similar to the flat figure quoted by other entities, citing

Table 5: Kinder-Morgan Pipeline Cost Metrics [17]

Terrain	Capital Cost ($/inch-Diameter/mile)
Flat, Dry	$50,000
Mountainous	$85,000
Marsh, Wetland	$100,000
River	$300,000
High Population	$100,000
Offshore (150'-200' depth)	$700,000

storage costs ranging from $0.40 to $4.00 per short ton of CO_2 removed [20]. This figure is based on sequestration in a saline formation in North America.

A second range of costs is also reported, citing CO_2 sequestration costs as ranging from $14 to $23 per short ton of CO_2 [13]. This range is based on a Monte Carlo analysis of 300 gigatonnes (Gt) of CO_2 storage in North America [20]. This analysis is inclusive of all storage options (geologic, enhanced oil recovery, enhanced coal bed methane, etc.), some of which are relatively high cost. This methodology may provide a more accurate cost estimate for large-scale, long-term deployment of CCS, but is a very high estimate for storage options that will be used in the next 50 to 100 years. For example, 300 Gt of storage represents capacity to store CO_2 from the next ~150 years of coal generation (2,200 million metric tonnes CO_2 per year from coal in 2007, assuming 90% capture from all facilities), meaning that certain high cost reservoirs will not come into play for another 100 or 150 years. This $14 to $23 per short ton estimate was therefore not viewed as a representative comparison to the NETL metric.

Results

Figure 1 describes the capital costs associated with the T&S of 10,000 short tons of CO_2 per day (2.65 million metric tonnes per year) for pipelines of varying length. This storage rate requires one injection well and is representative of the CO_2 produced by a 380 MW_g super-critical pulverized coal power plant, assuming 90% of the CO_2 produced by the plant is captured. Figure 2 presents similar information for Fixed, Variable, and total (assuming 100% capacity) operating expenses. In both cases, storage costs remain constant as the CO_2 flow rate and reservoir parameters do not change. Also, transport costs – which are dependent on both pipeline length and diameter – constitute the majority of the combined transport and storage costs for pipelines greater than 50 miles in length.

The disproportionately high cost of CO_2 transport (compared to storage costs) shown in Figures 1 and 2, and the direct dependence of pipeline diameter on the transport capital cost, prompted investigation into the effects of pipeline distance and CO_2 flow rate on pipeline diameter. Figure 3 describes the minimum required pipeline diameter as a function of pipeline length, assuming a CO_2 flow rate of 10,000 short tons per day (at 100%

Figure 1: Capital Cost vs. Pipeline Length

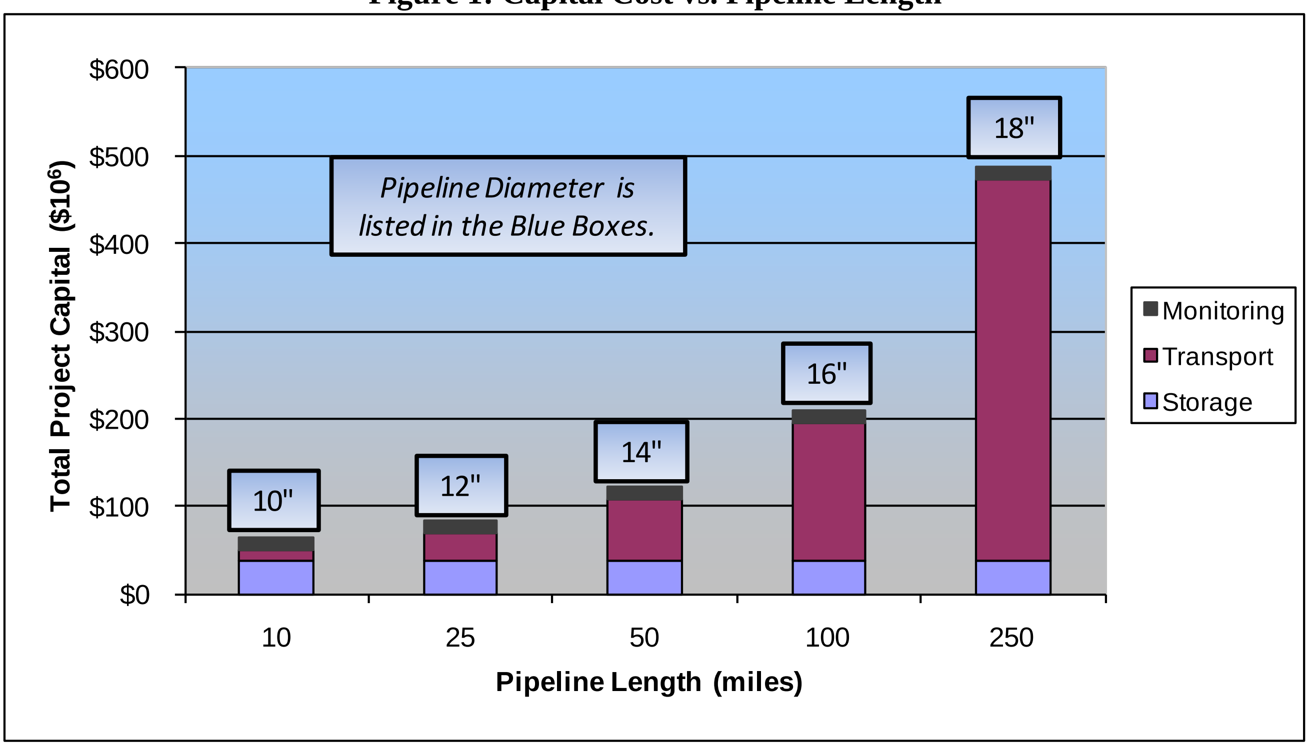
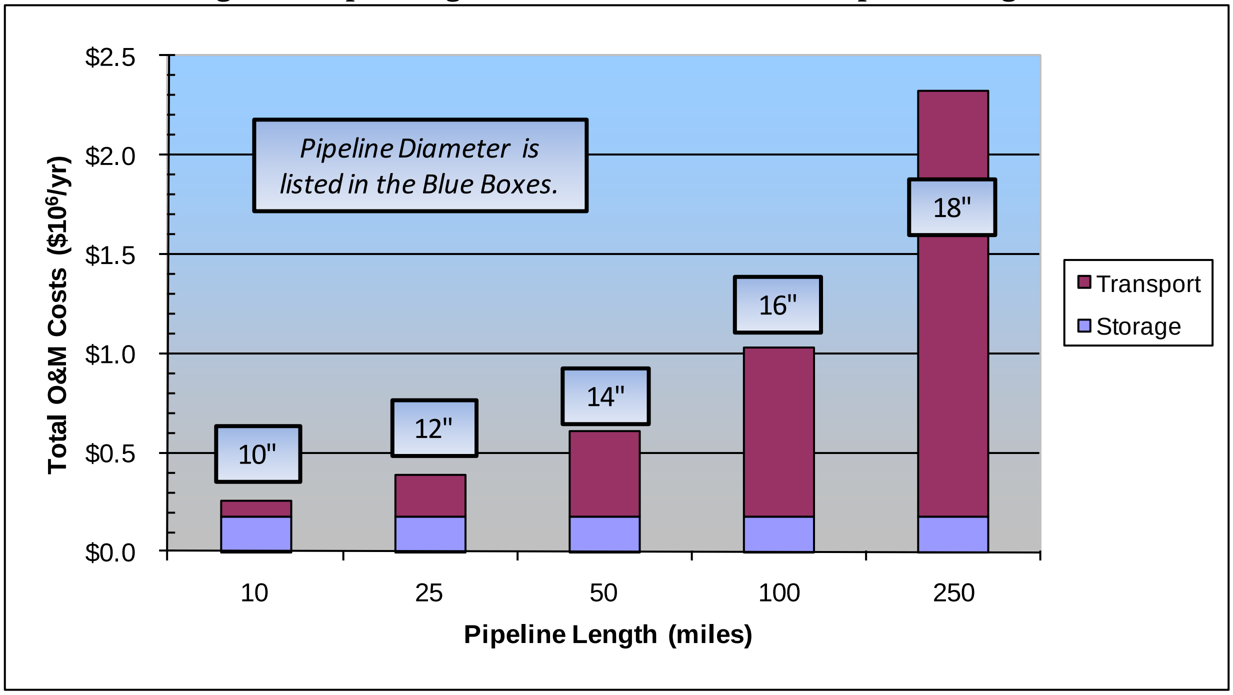


Figure 2: Operating and Maintenance Cost vs. Pipeline Length



utilization factor) and a pressure drop of 700 psi in order to maintain single phase flow in the pipeline (no recompression stages are utilized). Figure 4 is similar except that it describes the minimum pipe diameter as a function of CO_2 flow rate. A sensitivity analysis assessing the use of boost compressors and a smaller pipeline diameter has not yet been completed but may provide the ability to further reduce capital costs for sufficiently long pipelines.

Figure 3: Minimum Pipe Diameter as a function of Pipeline Length

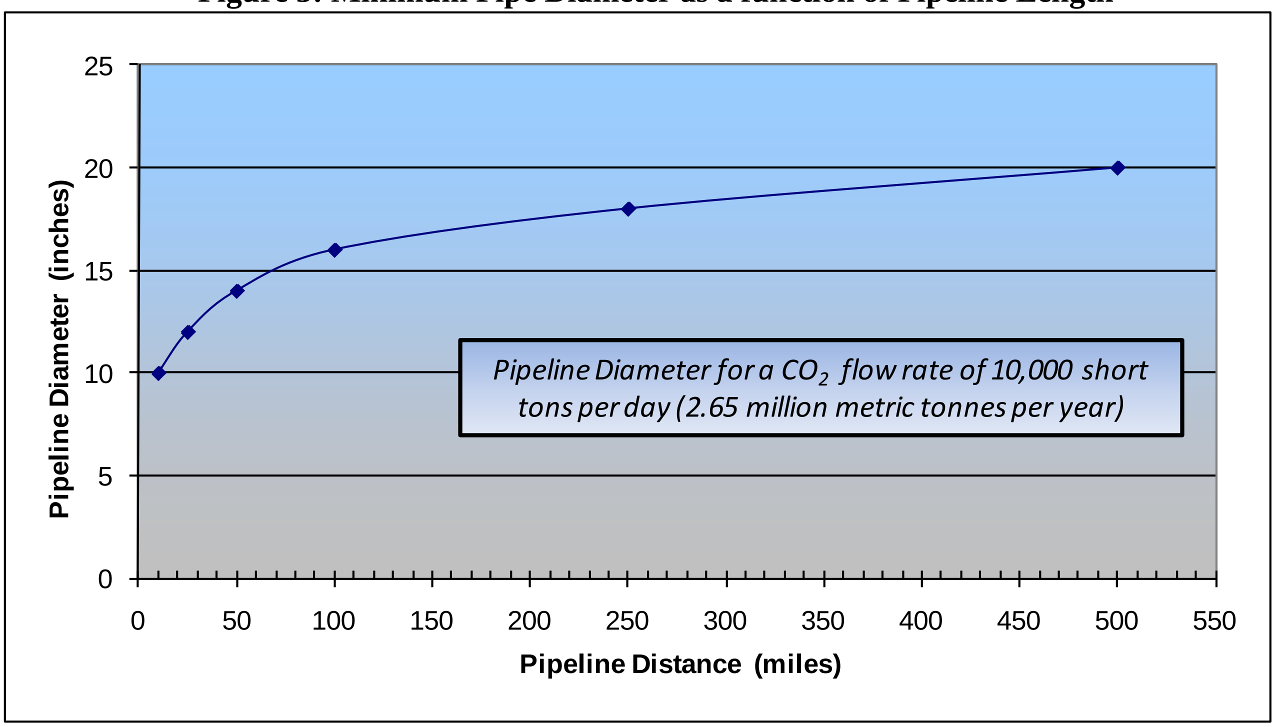
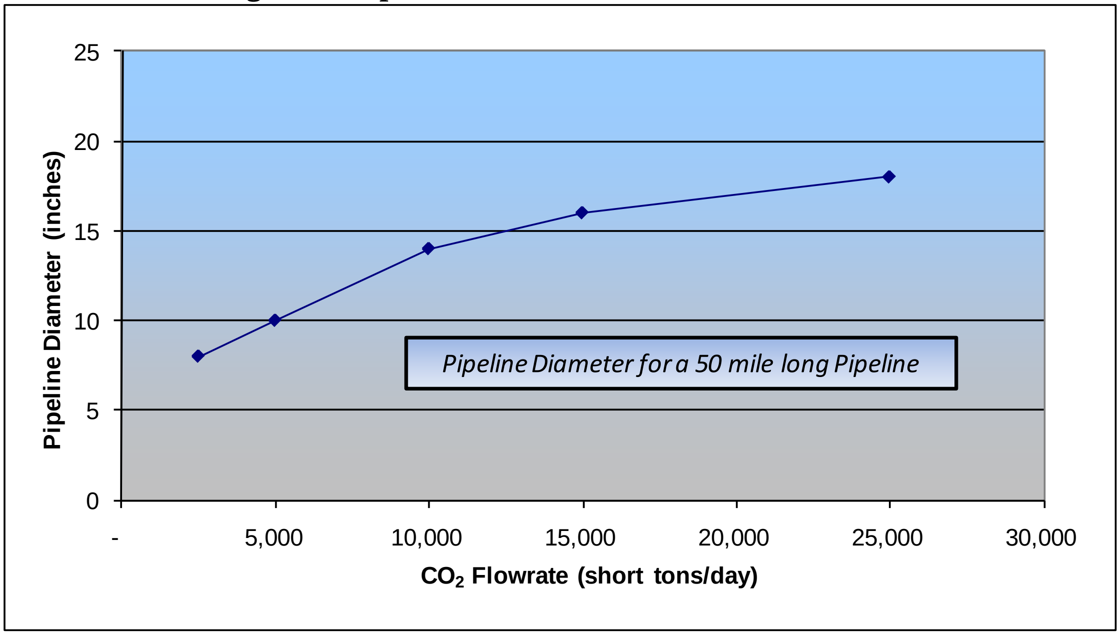


Figure 4: Pipe Diameter as a Function of CO_2 Flow Rate



Figures 5 and 6 describe the relationship of T&S costs to the flow rate of CO_2. The costs are evaluated for a 50 mile pipeline and a 700 psig CO_2 pressure drop over the length of the pipeline. Storage capital costs remain constant up until 10,000 short tons of CO_2 per day, above which a second injection well is needed and the cost increases as shown in Figure 5. A third injection well is needed for flow rates above 21,000 short tons per day and the capital requirement increases again for the 25,000 short tons per day flow rate due to an increase in pipeline diameter. Transport capital costs outweigh storage costs for all cases, as expected based on the results shown in Figure 1.

Unlike storage capital costs, the operating costs for storage constitute a significant portion of the total annual O&M costs – up to 44% at 25,000 short tons of CO_2 per day – as shown in Figure 6. Transport operating costs are constant with flow rate based on a constant pipeline length.

Figure 5: Capital Requirement vs. CO_2 Flow Rate

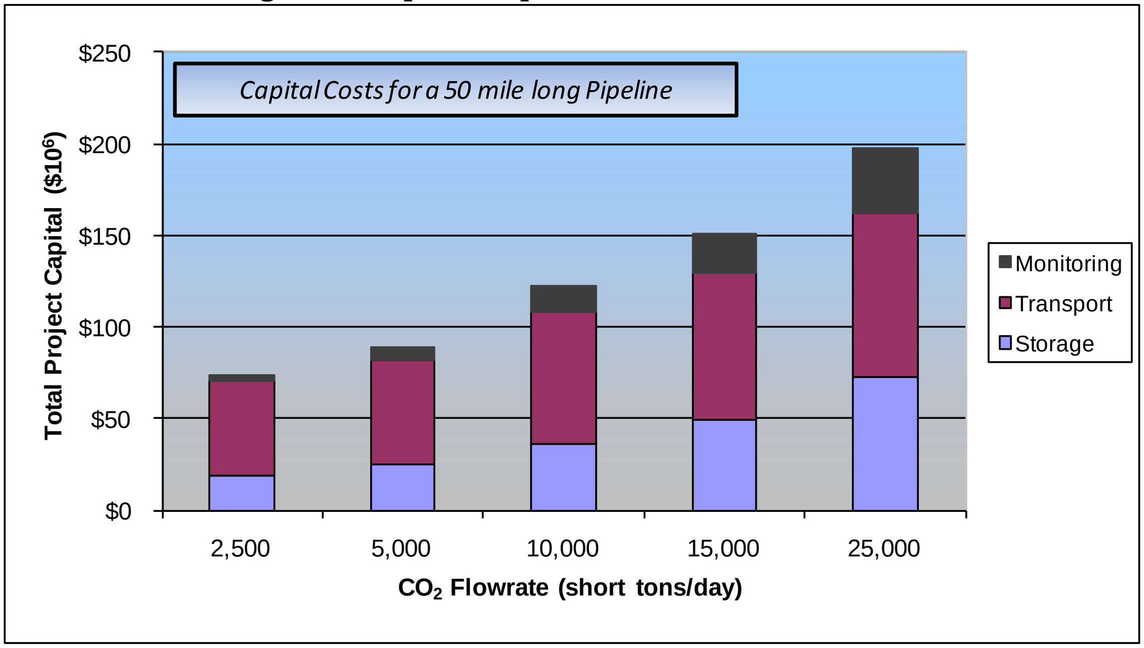
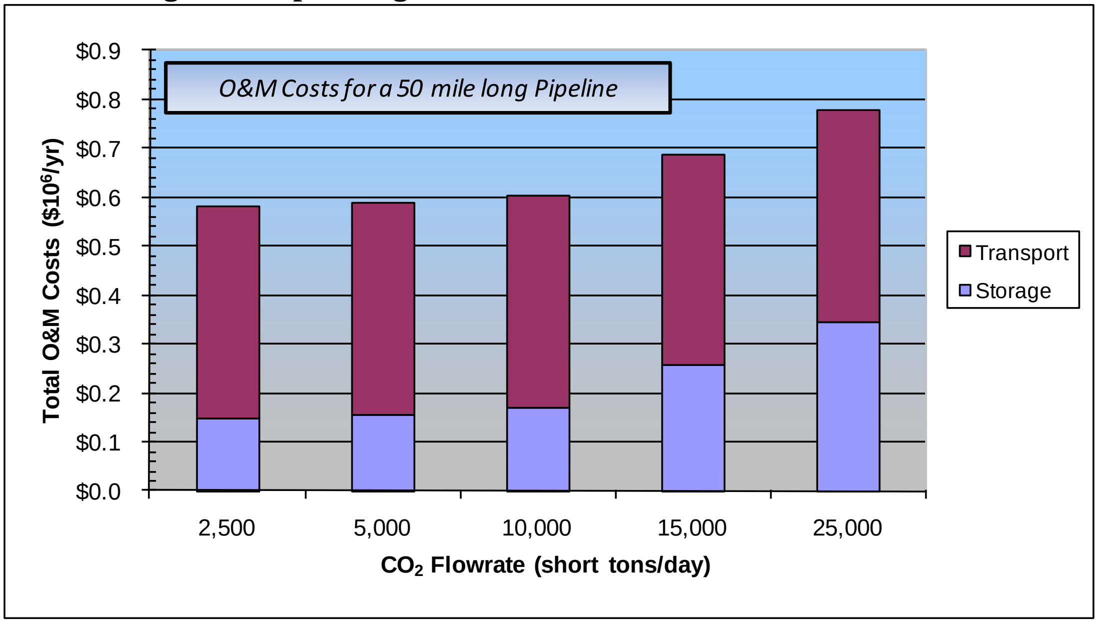
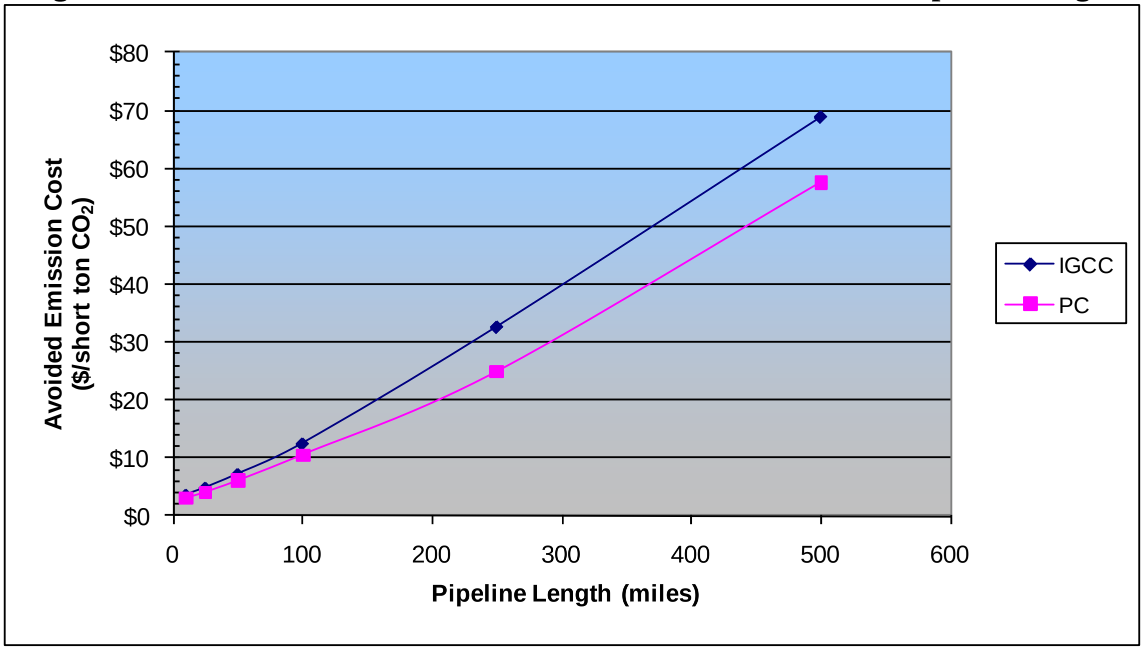


Figure 6: Operating and Maintenance Cost vs. CO_2 Flow Rate



Lastly, CO_2 avoidance and removal costs associated with T&S were determined for PC and IGCC reference plants found in the Baseline Study.[4] Because the CO_2 flow rate is defined by the reference plant, costs were determined as a function of pipeline length. Figure 7 shows that T&S avoided costs increase almost linearly with pipeline length and that there is very little difference between the PC and IGCC cases. This is the result of identical pipelines for each case (same distance, identical diameter) with only a change in capacity factor for each case. Figure 8 is similar to Figure 7 and shows the T&S removed emission cost.

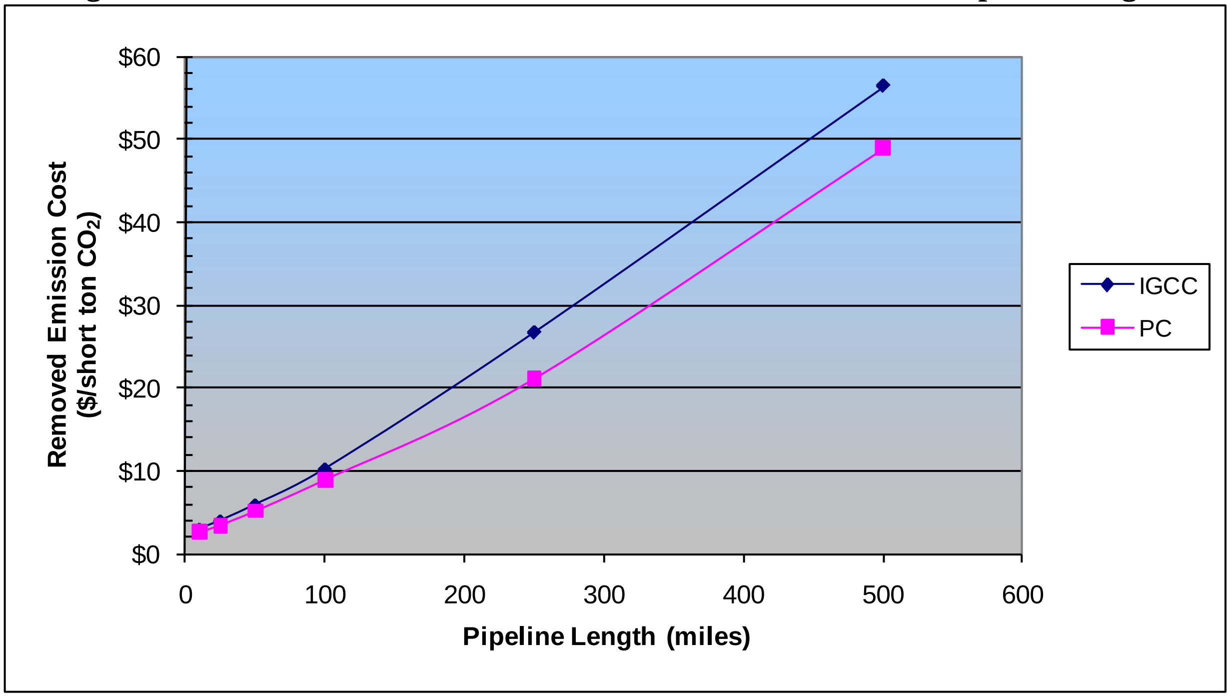
Figure 7: Avoided Emission Costs for 550 MW Power Plants vs. Pipeline Length



[4] Avoided cost calculations are based upon a levelized cost of electricity reported in Volume 1 of NETL's *Cost and Performance Baseline for Fossil Energy Plants* study. Electricity costs are levelized over a 30 year period, utilize a capital charge factor of 0.175, and levelization factors of 1.2022 and 1.1568 for coal costs and general O&M costs, respectively [3].

Addressing our initial topic, we see that our T&S avoided emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for the reference reservoir and our IGCC reference plant, or 50 to 95 miles for our PC reference plant. The T&S removal cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.

Figure 8: Removed Emission Costs for 550 MW Power Plants vs. Pipeline Length



Conclusions

- T&S avoided emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 30 to 75 miles for our reference IGCC plant and the reference reservoir found in Table 1, or pipeline lengths of 50 to 95 miles for the PC plant.
- T&S removed emission cost of $5 to $10 per short ton of CO_2 is associated with a pipeline length of 40 to 100 miles for an IGCC and 40 to 115 for a PC plant. Both of these ranges apply to the reference reservoir found in Table 1.
- Capital costs associated with CO_2 storage become negligible compared to the cost of transport (i.e. pipeline cost) for pipelines of 50 miles or greater in length.
- Transport and storage operating costs are roughly equivalent for a 25 mile pipeline but transport constitutes a much greater portion of operating expenses at longer pipeline lengths.
- Transport capital requirements outweigh storage costs, independent of CO_2 flow rate, at a pipeline length of 50 miles and the reference reservoir.
- Operating expenses associated with storage approach transport operating costs for flow rates of 25,000 short tons of CO_2 per day at a 50 mile pipeline length.

Future Work

This paper has identified a number of areas for investigation in future work. These include:

- Investigation into the apparent wide variability in site characterization and evaluation costs, including a sensitivity analysis to be performed to determine the sensitivity of overall project costs across the reported range of values.

- Continued research into liability costs and requirements.

- Further evaluation and sensitivity analysis into the number of land-owners pore space rights will have to be acquired from for a given sequestration project.

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APPENDIX E

BACT Cost Analysis

Cost Estimation for Transfer of CO_2 via Pipeline - RTO(Controls Amine Vent and Glycol Dehydrator)

CO_2 Pipeline and Emissions Data

Parameter	Value	Units
Minimum Length of Pipeline	110	miles
Average Diameter of Pipeline	8	inches
CO_2 emissions from RTO	116,170.13	Short tons/yr
CO_2 Capture Efficiency	90%	
Captured CO_2	104,553	Short tons/yr

CO_2 Transfer Cost Estimation [1]

Cost Type	Units	Cost Equation	Cost ($)
Pipeline Costs			
Materials	$ Diameter (inches), Length (miles)	$64,632 + $1.85 x L x (330.5 x D² + 686.7 x D + 26,960)	$10,973,371.60
Labor	$ Diameter (inches), Length (miles)	$341,627 + $1.85 x L x (343.2 x D2 + 2,074 x D + 170,013)	$42,785,581.30
Miscellaneous	$ Diameter (inches), Length (miles)	$150,166 + $1.58 x L x (8,417 x D + 7,234)	$13,110,432.00
Right of Way	$ Diameter (inches), Length (miles)	$48,037 + $1.20 x L x (577 x D +29,788)	$4,589,365.00
Other Capital			
CO_2 Surge Tank	$	$1,150,636	$1,150,636.00
Pipeline Control System	$	$110,632	$110,632.00
Operation & Maintenance (O&M)			
Fixed O&M	$/mile/yr	$8,632	$949,520.00
		Total Pipeline Cost	**$73,669,537.90**

Amortized Cost Calculation

Equipment Life [2]	10	years
Interest rate [3]	7%	
Capital Recovery Factor (CRF) [4]	0.14	
Total Pipeline Installation Cost (TCI)	$72,720,018	$ (Pipeline + Other Capital)
Amortized Installation Cost (TCI *CRF)	$10,353,695	$/yr
Amortized Installation + O&M Cost	$11,303,215	$/yr
CO_2 Transferred	104,553	Short tons/yr
Annuitized control cost per ton [5]	**108**	**$/ton-yr**

[1] Cost estimation guidelines obtained from "Quality Guidelines for Energy System Studies Estimating Carbon Dioxide Transport and Storage Costs", DOE/NETL-2010/1447, dated March 2010.

[2] Pipeline life is assumed based on engineering judgment.

[3] Interest rate conservatively set at 7.00%, based on EPA's seven percent social interest rate from the OAQPS CCM Sixth Edition.

[4] Capital Recovery Fraction = Interest Rate (%) x (1+ Interest Rate (%)) ^ Pipeline Life) / ((1 + Interest Rate (%)) ^ Pipeline Life - 1)

[5] This cost estimation does not include capital and O&M costs associated with the compression equipment or processing equipment.

APPENDIX F

Equipment Tables

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA					
Number from flow diagram: EPN 5			Model Number(if available):		
Name of device: Regenerative Thermal Oxidizer			Manufacturer		
CHARACTERISTICS OF INPUT					
Waste Material*	Chemical Composition				
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr	
	1. See attached emission calculations for details				
	2.				
	3.				
	4.				
	5.				
Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb ______	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia) ________	Maximum SCFM(70°F & 14.7 psia) __________	
Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F		
	Minimum Expected ________	Design Maximum 27,683	Minimum Expected ________	Design Maximum ________	
Fuel	Chemical Composition				
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr	
	1. No supplemental fuel during normal operation				
	2.				
	3.				
	4.				
Gross Heating Value of Fuel	Btu/lb ___	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia) ________	Maximum SCFM(70°F & 14.7 psia) ________	

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
Flue Gas Released	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. See attached emission calculations for details			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected
600				51.97

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft^3	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
Average Residence Time sec	Exhaust Stack Height ft	Exhaust Stack Diameter ft
	30.00	3.50

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

TABLE 6

BOILERS AND HEATERS

Type of Device: TEG Reboiler			Manufacturer:	
Number from flow diagram: EPN 1			Model Number:	
CHARACTERISTICS OF INPUT				
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	See attached emission calculations for Residue Gas composition		Average	Design Maximum 17,420 scf/hr
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM						
Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS			
Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
16 in	16.67 ft		3.47 fps	750 deg	665 acfm

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: HTR-1 Regen Heater	Manufacturer:
Number from flow diagram: EPN 3	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average	Design Maximum
Natural Gas	See attached emission calculations for Residue Gas composition			52,800 scf/hr
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
2.5 ft	18 ft		6.45 fps	680 deg F	1,900 acfm

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: Hot Oil Heater	Manufacturer:
Number from flow diagram: EPN 4	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	See attached emission calculations for Residue Gas composition		Average	Design Maximum 935,196 scf/hr
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
6.75 in	124 ft		13.89 fps	550 deg F	29,815 acfm

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 7(b)

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,085 m E, 3,686,958 m N
3. Tank No. 11   4. Emission Point No. EPN 11
5. FIN FIN 11   CIN ______
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Length : 10.75 ft.
   b. Diameter: 4 ft.
   c. Nominal Capacity or Working Volume: 1,000 gallons.
   d. Turnovers per year: 52.0
   e. Net Throughput : 52,000 gallons/year.
   f. Maximum Filling Rate: 1,000 gallons/hour.
   g. Is the tank underground? Yes [ ] No [X]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [X] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	atmosphere
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Permit No. ____________________ Tank No. EPN 11

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [X] *Complete Section III.3*

   Multiple [ ] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Methyl Alcohol
   b. CAS Number: 67-56-1
   c. Average Liquid Surface Temperature: 73.27 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 2.220 psia.
   e. Liquid Molecular Weight: 32.04
4. Multiple Component Information
   a. Mixture Name: ____________________
   b. Average Liquid Surface Temperature: ________ °F.
   c. Minimum Liquid Surface Temperature: ________ °F.
   d. Maximum Liquid Surface Temperature: ________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: ________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: ________ psia.
   h. Liquid Molecular Weight: ________
   i. Vapor Molecular Weight: ________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,360 m E, 3,686,790 m N
3. Tank No. 16 4. Emission Point No. EPN 16
5. FIN FIN 16 CIN ________
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ________)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ________)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ________ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	atmosphere
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. EPN 16

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________
   b. CAS Number: ______________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Produced water
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank).*

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,363 m E, 3,686,793 m N
3. Tank No. 17 4. Emission Point No. EPN 17
5. FIN FIN 17 CIN VRU
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	VRU; atmosphere during VRU downtime
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ______________________ Tank No. EPN 17

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____
   b. CAS Number: ___________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: _______ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank).*

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,363 m E, 3,686,793 m N
3. Tank No. 18 4. Emission Point No. EPN 18
5. FIN FIN 18 CIN VRU
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	VRU; atmosphere during VRU downtime
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. EPN 18

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram	Manufacturer & Model No. (if available)
EPN 6	

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	See attached emission calculations for details		
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	See attached emission calculations for details			
Fuel Added to Gas Steam				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	3	Natural Gas	0.833 scfm/pilot

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min.Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft) 75 ft	Flare tip inside diameter (ft) 1.67 ft
Capital Installed Cost $____________	Annual Operating Cost $_____________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70° F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Inlet Gas	None	200 MMscf/day		X	
Refrigerant Propane	20	30,000 gal/yr		X	
2. Fuels - Input					
Natural Gas		Fuel is from plant residue gas.			
3. Products & By-Products - Output					
Residue Gas	none	160 MMscf/day		X	
High Pressure Condensate	none	345000 bbl/yr		X	
Low Pressure Condensate	17, 18	416,000 gal/yr		X	
NGLs	none	8,256,000 bbl/yr		X	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
Produced Water	16	416,000 gal/yr		X	
6. Airborne Waste (Solid) - Output	See Table 1(a)	See Emissions Data section			X
7. Airborne Wastes (Gaseous) - Output	See Table 1(a)	See Emissions Data section			X

APPENDIX G

TCEQ Minor NSR Permit Application

12770 Merit Drive | Suite 900 | Dallas, TX 75251 | P (972) 661-8100 | F (972) 385-9203
trinityconsultants.com

Trinity Consultants

February 17, 2012

Air Permits Initial Review Team
Texas Commission on Environmental Quality
12100 Park 35 Circle, MC 161
Building C, Third Floor, Room 300W
Austin, TX 78753

RE: TCEQ Air Quality New Source Review Initial Permit Application
Targa Gas Processing LLC – Longhorn Gas Plant
Wise County, Texas
Customer Reference Number: TBA
Regulated Entity Reference Number: TBA

Dear Air Permits Initial Review Team:

Targa Gas Processing LLC (Targa) is proposing to construct a natural gas processing plant near Decatur in Wise County, Texas (Longhorn Gas Plant). The primary Standard Industrial Classification code of the proposed Longhorn Gas Plant is 1321 (Natural Gas Liquids). The Longhorn Gas Plant will be designed to process up to 200 million standard cubic feet per day of sweet natural gas. The Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, a glycol dehydration unit, a cryogenic processing skid and supporting equipment. The proposed facility will be a minor source with respect to all criteria pollutants and hazardous air pollutants. Targa is submitting this air quality new source review (NSR) permit application to the Texas Commission on Environmental Quality (TCEQ) authorize construction of the Longhorn Gas Plant.

The proposed Longhorn Gas Plant will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements under the GHG Tailoring Rule. With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action. Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs. As shown in the enclosed permit application, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG pollutants. Therefore, all non-GHG pollutants are subject to the jurisdiction of the TCEQ for minor source state NSR permitting. Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The GHG PSD application submitted to EPA is included as an appendix of this TCEQ NSR permit application for reference.

The enclosed TCEQ minor source NSR permit application is prepared in accordance with 30 TAC Chapter 116, Subchapter B, New Source Review Permits. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control Technology evaluation, emissions calculations, process description and flow diagram, and supporting documentation. Targa Gas Processing LLC has not yet been assigned a TCEQ Customer Reference Number. Additionally, the Longhorn Gas Plant has not yet been assigned a TCEQ Regulated Entity Number. With this application, Targa has included a Core Data Form for the new company and the new facility.

If you have any questions or comments about the information presented in this letter, please do not hesitate to call Ms. Melanie Roberts, Targa, at (713) 584-1422.

Sincerely,

TRINITY CONSULTANTS

Jessica Coleman
Senior Consultant

Enclosure

cc: Ms. Alyssa Taylor, Air Section Manager, TCEQ Region 4
Mr. Clark White, VP & Region Manager, Targa
Ms. Jessica Keiser, Assistant VP ES&H, Targa
Ms. Melanie Roberts, Environmental Manager, Targa
Ms. Christine Chambers, Manager of Consulting Services - Dallas, Trinity Consultants

TCEQ AIR QUALITY NEW SOURCE REVIEW INITIAL PERMIT APPLICATION

Targa Gas Processing LLC> Longhorn Gas Plant

Prepared By:

Jessica Keiser – Assistant VP ES&H
Melanie Roberts – Environmental Manager

TARGA GAS PROCESSING LLC
1000 Louisiana St.
Suite 4300
Houston, TX 77002
(713) 584-1422
Fax: (713) 584-1100

Christine Chambers – Managing Consultant
Jessica Coleman – Senior Consultant
Latha Kambham – Senior Consultant
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12770 Merit Drive
Suite 900
Dallas, TX 75251
(972) 661-8100
Fax: (972) 385-9203

February 2012

Project 114401.0161

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1. EXECUTIVE SUMMARY

Targa Gas Processing LLC (Targa) is proposing to construct a natural gas processing plant near Decatur in Wise County, Texas (Longhorn Gas Plant). The primary Standard Industrial Classification code of the proposed Longhorn Gas Plant is 1321 (Natural Gas Liquids). The proposed facility will be a minor source with respect to all criteria pollutants and hazardous air pollutants (HAP). Targa is submitting this air quality new source review (NSR) permit application to authorize construction of the proposed Longhorn Gas Plant.

Targa Gas Processing LLC has not yet been assigned Texas Commission on Environmental Quality (TCEQ) Customer Reference Number, nor has the Longhorn Gas Plant been assigned a TCEQ Regulated Entity Number (RN). Therefore, with this application, Targa has included a Core Data Form in order to be assigned a new CN and RN.

1.1. PROPOSED PROJECT

The Longhorn Gas Plant will be designed to process up to 200 million standard cubic feet per day (MMscfd) of sweet natural gas. The Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, a glycol dehydration unit, a cryogenic processing skid and supporting equipment. The main processes at the Longhorn Gas Plant will include the following:

- Inlet separation facilities
- Removal of carbon dioxide (CO_2) from natural gas through amine treating
- Removal of water from natural gas through glycol dehydration and in molecular sieve dehydrator beds
- Separation of natural gas liquids from natural gas through a cryogenic process
- Compression of natural gas by electric-driven compressors
- Pipeline loading of high-pressure condensate liquids
- Truck loading of low-pressure condensate and produced water liquids

The proposed Longhorn Gas Plant will include the following emissions sources:

- Amine treater
- Tri-ethylene glycol (TEG) dehydrator
- Heaters
- Tanks
- Truck loading
- Regenerative thermal oxidizer (RTO)
- Process flare
- Planned maintenance, start-up, and shutdown (MSS) activities
- Equipment leak fugitives

1.2. PERMITTING CONSIDERATIONS

1.2.1. Nonattainment Designations

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified for all criteria pollutants.[1] In a letter dated December 9, 2011, the United States Environmental Protection Agency (U.S. EPA) expressed its intent to designate Wise County as nonattainment for the eight-hour ozone standard and include it in the existing Dallas-Fort Worth (DFW) ozone nonattainment area.[2] In the event of a redesignation of Wise County to a serious nonattainment, the proposed Longhorn Gas Plant would be potentially subject to nonattainment new source review (NNSR) requirements for nitrogen dioxides (NO_x) and volatile organic compounds (VOC) if potential emissions exceed 50 tons per year (tpy) of either NO_x or VOC. Section 11 of this permit application includes an analysis demonstrating that the proposed Longhorn Gas Plant would not be considered a major source for ozone precursors under the proposed nonattainment designation, and will not be subject to NNSR permitting requirements even if Wise County is redesignated a serious ozone nonattainment area.

1.2.2. Greenhouse Gas Permitting Requirements

The proposed Longhorn Gas Plant will be a new major source with respect to greenhouse gas (GHG) emissions and subject to Prevention of Significant Deterioration (PSD) permitting requirements as EPA has interpreted them in the GHG Tailoring Rule.[3] In the Tailoring Rule, EPA established a major source threshold of 100,000 tpy CO_2e for new GHG sources. Targa has determined that the GHG emissions from the proposed project will exceed 100,000 tpy as shown in the GHG PSD application included in Appendix G of this application. As a result, Targa has concluded that the proposed Longhorn Gas Plant will be a new major source with respect to GHGs.

With a final action published in May 2011, EPA promulgated a Federal Implementation Plan (FIP) to implement the permitting requirements for GHGs in Texas, and EPA assumed the role of permitting authority for Texas GHG permit applications with that action.[4] Therefore, GHG emissions from the proposed facility are subject to the jurisdiction of the EPA under authority EPA has asserted in Texas through its FIP for the regulation of GHGs.

As shown in Section 11 of this permit application, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG pollutants. Therefore, all non-GHG emissions are subject to the jurisdiction of the TCEQ for minor source state NSR permitting.

Accordingly, Targa is submitting applications to both EPA and TCEQ to obtain the requisite authorizations to construct. The GHG PSD application submitted to EPA is included in Appendix G of this TCEQ NSR permit application for reference.

1.3. PERMIT APPLICATION

This permit application was prepared in accordance with 30 TAC Chapter 116, Subchapter B, New Source Review Permits. This application includes a TCEQ Form PI-1, other applicable TCEQ forms, a Best Available Control

[1] Per 40 CFR §81.344 (Effective April 5, 2005).

[2] Letter from Dr. Al Armendariz, U.S. EPA Region 6 Administrator, to Texas Governor Rick Perry, dated December 9, 2011.

[3] Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, 75 Fed. Reg. 31,514 (June 3, 2010).

[4] Determinations Concerning Need for Error Correction, Partial Approval and Partial Disapproval, and Federal Implementation Plan Regarding Texas's Prevention of Significant Deterioration Program, 76 Fed. Reg. 25,178 (May 3, 2011).

Technology (BACT) evaluation, emissions calculations, process description and flow diagram, and other supporting documentation.

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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: Targa Gas Processing LLC		
Texas Secretary of State Charter/Registration Number (*if applicable*):		
B. Company Official Contact Name: Clark White		
Title: VP & Region Manager		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1525	Fax No.:	E-mail Address:
C. Technical Contact Name: Melanie Roberts		
Title: Environmental Manager		
Company Name: Targa Gas Processing LLC		
Mailing Address: 1000 Louisiana Street, Suite 4300		
City: Houston	State: TX	ZIP Code: 77002
Telephone No.: 713-584-1422	Fax No.: 713-584-1522	E-mail Address: mroberts@targaresources.com
D. Site Name: Longhorn Gas Plant		
E. Area Name/Type of Facility: Natural Gas Processing Plant		☒ Permanent ☐ Portable
F. Principal Company Product or Business: Natural Gas Processing		
Principal Standard Industrial Classification Code (SIC): 1321		
Principal North American Industry Classification System (NAICS):		
G. Projected Start of Construction Date: 11/01/2012		
Projected Start of Operation Date: 06/01/2013		
H. Facility and Site Location Information (If no street address, provide clear driving directions to the site in writing.):		
Street Address:		
NE on FM51 from US-380, turn left after 5.4 miles. Drive 1.25 miles to plant.		
City/Town: Decatur	County: Wise	ZIP Code: 76234
Latitude (nearest second): 33.310930	Longitude (nearest second): -97.526777	

I. Applicant Information (continued)	
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 or enforcement action? If *Yes*, attach a copy of any correspondence from the agency.	☐ YES ☒ NO
C. Number of New Jobs: 86	
D. Provide the name of the State Senator and State Representative and district numbers for this facility site:	
Senator: Craig Estes	District No.: 30
Representative: Phil King	District No.: 61
III. Type of Permit Action Requested	
A. Mark the appropriate box indicating what type of action is requested. Initial ☒ Amendment ☐ Revision (30 TAC 116.116(e)) ☐ Change of Location ☐ Relocation ☐	
B. Permit Number (if existing):	
C. Permit Type: Mark the appropriate box indicating what type of permit is requested. *(check all that apply, skip for change of location)* Construction ☒ Flexible ☐ Multiple Plant ☐ Nonattainment ☐ Prevention of Significant Deterioration ☐ Hazardous Air Pollutant Major Source ☐ Plant-Wide Applicability Limit ☐ Other:______________________________	
D. Is a permit renewal application being submitted in conjunction with this amendment in accordance with 30 TAC 116.315(c).	☐ YES ☒ NO

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

III. Type of Permit Action Requested (continued)		
H.	Federal Operating Permit Requirements (30 TAC Chapter 122 Applicability) *(continued)*	
2.	Identify the type(s) of FOP(s) issued and/or FOP application(s) submitted/pending for the site. (check all that apply)	
GOP Issued ☐	GOP application/revision application submitted or under APD review ☐	
SOP Issued ☐	SOP application/revision application submitted or under APD review ☐	
IV. Public Notice Applicability		
A.	Is this a new permit application or a change of location application?	☒ YES ☐ NO
B.	Is this application for a concrete batch plant? If Yes, complete V.C.1 – V.C.2.	☐ YES ☒ NO
C.	Is this an application for a major modification of a PSD, nonattainment, FCAA 112(g) permit, or exceedance of a PAL permit?	☐ YES ☒ NO
D.	Is this application for a PSD or major modification of a PSD located within 100 kilometers of an affected state?	☐ YES ☒ NO
If *Yes*, list the affected state(s).		
E.	Is this a state permit amendment application? If Yes, complete IV.E.1. – IV.E.3.	
1.	Is there any change in character of emissions in this application?	☐ YES ☐ NO
2.	Is there a new air contaminant in this application?	☐ YES ☐ NO
3.	Do the facilities handle, load, unload, dry, manufacture, or process grain, seed, legumes, or vegetables fibers (agricultural facilities)?	☐ YES ☐ NO
F.	List the total annual emission increases associated with the application (*list* **all** *that apply and attach additional sheets as needed*): **Please see Emission Data Section in Report**	
Volatile Organic Compounds (VOC):		
Sulfur Dioxide (SO_2):		
Carbon Monoxide (CO):		
Nitrogen Oxides (NO_x):		
Particulate Matter (PM):		
PM $_{10}$ microns or less (PM_{10}):		
PM $_{2.5}$ microns or less ($PM_{2.5}$):		
Lead (Pb):		
Hazardous Air Pollutants (HAPs):		
Other speciated air contaminants **not** listed above:		

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V. Public Notice Information (complete if applicable)			
A. Public Notice Contact Name: Shane Tribe			
Title: Environmental Specialist			
Mailing Address: 383 CR 1745			
City: Chico	State: TX	ZIP Code: 76431	
B. Name of the Public Place: Decatur Public Library			
Physical Address (No P.O. Boxes): 1700 S FM 51			
City: Decatur	County: Wise	ZIP Code: 76234	
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
C. Concrete Batch Plants, PSD, and Nonattainment Permits			
1. County Judge Information (For Concrete Batch Plants and PSD and/or Nonattainment Permits) for this facility site.			
The Honorable:			
Mailing Address:			
City:	State:	ZIP Code:	
2. Is the facility located in a municipality or an extraterritorial jurisdiction of a municipality? *(For Concrete Batch Plants)*			☐ YES ☐ NO
Presiding Officers Name(s):			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	
3. Provide the name, mailing address of the chief executives of the city and county, Federal Land Manager, or Indian Governing Body for the location where the facility is or will be located.			
Chief Executive:			
Mailing Address:			
City:	State:	ZIP Code:	
Name of the Federal Land Manager:			
Title:			
Mailing Address:			
City:	State:	ZIP Code:	

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

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VII. Technical Information			
B. Are any schools located within 3,000 feet of this facility?			☐ YES ☒ NO
C. Maximum Operating Schedule:			
Hours: 24 hr/day	Day(s): 7 day/wk	Week(s): 52 wk/yr	Year(s): 8,760 hr/yr
Seasonal Operation? If Yes, please describe in the space provide below.			☐ YES ☒ NO
D. Have the planned MSS emissions been previously submitted as part of an emissions inventory?			☐ YES ☒ NO
Provide a list of each planned MSS facility or related activity and indicate which years the MSS activities have been included in the emissions inventories. Attach pages as needed.			
E. Does this application involve any air contaminants for which a *disaster review* is required?			☐ YES ☒ NO
F. Does this application include a pollutant of concern on the *Air Pollutant Watch List (APWL)*?			☐ YES ☒ NO
VIII. State Regulatory Requirements **Applicants must demonstrate compliance with all applicable state regulations to obtain a permit or amendment**. *The application must contain detailed attachments addressing applicability or non applicability; identify state regulations; show how requirements are met; and include compliance demonstrations.*			
A. Will the emissions from the proposed facility protect public health and welfare, and comply with all rules and regulations of the TCEQ?			☒ YES ☐ NO
B. Will emissions of significant air contaminants from the facility be measured?			☒ YES ☐ NO
C. Is the Best Available Control Technology (BACT) demonstration attached?			☒ YES ☐ NO
D. Will the proposed facilities achieve the performance represented in the permit application as demonstrated through recordkeeping, monitoring, stack testing, or other applicable methods?			☒ YES ☐ NO
IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** *The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.*			
A. Does Title 40 Code of Federal Regulations Part 60, (40 CFR Part 60) New Source Performance Standard (NSPS) apply to a facility in this application?			☒ YES ☐ NO
B. Does 40 CFR Part 61, National Emissions Standard for Hazardous Air Pollutants (NESHAP) apply to a facility in this application?			☐ YES ☒ NO
C. Does 40 CFR Part 63, Maximum Achievable Control Technology (MACT) standard apply to a facility in this application?			☒ YES ☐ NO

IX. Federal Regulatory Requirements **Applicants must demonstrate compliance with all applicable federal regulations to obtain a permit or amendment** ***The application must contain detailed attachments addressing applicability or non applicability; identify federal regulation subparts; show how requirements are met; and include compliance demonstrations.***	
D. Do nonattainment permitting requirements apply to this application?	☐ YES ☒ NO
E. Do prevention of significant deterioration permitting requirements apply to this application?	☐ YES ☒ NO
F. Do Hazardous Air Pollutant Major Source [FCAA 112(g)] requirements apply to this application?	☐ YES ☒ NO
G. Is a Plant-wide Applicability Limit permit being requested?	☐ YES ☒ NO
X. Professional Engineer (P.E.) Seal	
Is the estimated capital cost of the project greater than $2 million dollars?	☒ YES ☐ NO
If *Yes*, submit the application under the seal of a Texas licensed P.E.	
XI. Permit Fee Information	
Check, Money Order, Transaction Number ,ePay Voucher Number: 549317	Fee Amount: $75,000
Company name on check: Targa Resources Partners LP	Paid online?: ☐ YES ☒ NO
Is a copy of the check or money order attached to the original submittal of this application?	☒ YES ☐ NO ☐ N/A
Is a Table 30 (Form 10196) entitled, Estimated Capital Cost and Fee Verification, attached?	☒ YES ☐ NO ☐ N/A

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

XII. Delinquent Fees and Penalties
This form **will not be processed** until all delinquent fees and/or penalties owed to the TCEQ or the Office of the Attorney General on behalf of the TCEQ is paid in accordance with the Delinquent Fee and Penalty Protocol. For more information regarding Delinquent Fees and Penalties, go to the TCEQ Web site at: www.tceq.texas.gov/agency/delin/index.html.
XIII. Signature
The signature below confirms that I have knowledge of the facts included in this application and that these facts are true and correct to the best of my knowledge and belief. I further state that to the best of my knowledge and belief, the project for which application is made will not in any way violate any provision of the Texas Water Code (TWC), Chapter 7, Texas Clean Air Act (TCAA), as amended, or any of the air quality rules and regulations of the Texas Commission on Environmental Quality or any local governmental ordinance or resolution enacted pursuant to the TCAA I further state that I understand my signature indicates that this application meets all applicable nonattainment, prevention of significant deterioration, or major source of hazardous air pollutant permitting requirements. The signature further signifies awareness that intentionally or knowingly making or causing to be made false material statements or representations in the application is a criminal offense subject to criminal penalties.
Name: Clark White
Signature: Clark White *Original Signature Required*
Date: 2/16/2012

TCEQ

TCEQ Use Only

TCEQ Core Data Form

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)*			
☒	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. Attachments	Describe Any Attachments: *(ex. Title V Application, Waste Transporter Application, etc.)*
☒Yes ☐No	Air New Source Review Permit Application

3. Customer Reference Number *(if issued)*	Follow this link to search for CN or RN numbers in Central Registry**	4. Regulated Entity Reference Number *(if issued)*
CN		RN

SECTION II: Customer Information

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

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

☐Owner	☐ Operator	☒ Owner & Operator	
☐Occupational Licensee	☐ Responsible Party	☐ Voluntary Cleanup Applicant	☐Other: ____________

7. General Customer Information

☒ New Customer	☐ Update to Customer Information	☐ Change in Regulated Entity Ownership
☐Change in Legal Name (Verifiable with the Texas Secretary of State)		☐ No Change**

*****If "No Change" and Section I is complete, skip to Section III – Regulated Entity Information.***

8. Type of Customer:	☒ Corporation	☐ Individual	☐ Sole Proprietorship- D.B.A
☐ City Government	☐ County Government	☐ Federal Government	☐ State Government
☐ Other Government	☐ General Partnership	☐ Limited Partnership	☐ Other: ____________

9. Customer Legal Name *(If an individual, print last name first: ex: Doe, John)*	*If new Customer, enter previous Customer below*	*End Date:*
Targa Gas Processing LLC		

10. Mailing Address:	1000 Louisiana Street, Suite 4300						
	City	Houston	State	TX	ZIP	77002	ZIP + 4

11. Country Mailing Information *(if outside USA)*	12. E-Mail Address *(if applicable)*

13. Telephone Number	14. Extension or Code	15. Fax Number *(if applicable)*
(713) 584-1000		( ) -

16. Federal Tax ID *(9 digits)*	17. TX State Franchise Tax ID *(11 digits)*	18. DUNS Number *(if applicable)*	19. TX SOS Filing Number *(if applicable)*
760507891	17605078918		

20. Number of Employees	21. Independently Owned and Operated?
☐ 0-20 ☐ 21-100 ☐ 101-250 ☐ 251-500 ☒ 501 and higher	☒ Yes ☐ No

SECTION III: Regulated Entity Information

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

☒ New Regulated Entity ☐ Update to Regulated Entity Name ☐ Update to Regulated Entity Information ☐ No Change** *(See below)*

**If "NO CHANGE" is checked and Section I is complete, skip to Section IV, Preparer Information.

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

Longhorn Gas Plant

24. Street Address of the Regulated Entity: *(No P.O. Boxes)*							
	City		**State**		**ZIP**		**ZIP + 4**
25. Mailing Address:	383 County Road 1745						
	City	Chico	**State**	TX	**ZIP**	76431	**ZIP + 4**
26. E-Mail Address:	mroberts@targaresources.com						

27. Telephone Number	28. Extension or Code	29. Fax Number *(if applicable)*
(940) 644-2233		( ) -

30. Primary SIC Code (4 digits)	31. Secondary SIC Code (4 digits)	32. Primary NAICS Code (5 or 6 digits)	33. Secondary NAICS Code (5 or 6 digits)
1321			

34. What is the Primary Business of this entity? *(Please do not repeat the SIC or NAICS description.)*

Natural Gas Processing

Questions 34 – 37 address geographic location. Please refer to the instructions for applicability.

35. Description to Physical Location:	NE on FM51 from US-380, turn left after 5.4 miles. Drive 1.25 miles to plant.

36. Nearest City	County	State	Nearest ZIP Code
Decatur	Wise	TX	76234

37. Latitude (N) In Decimal:	33.310930°		38. Longitude (W) In Decimal:	-97.526777°	
Degrees	Minutes	Seconds	Degrees	Minutes	Seconds

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 or the updates may not be made. If your Program is not listed, check other and write it in. See the Core Data Form instructions for additional guidance.

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

SECTION IV: Preparer Information

40. Name:	Melanie Roberts	41. Title:	Environmental Manager
42. Telephone Number	**43. Ext./Code**	**44. Fax Number**	**45. E-Mail Address**
(713) 584-1422		(713) 584-1522	mroberts@targaresources.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 9 and/or as required for the updates to the ID numbers identified in field 39.

(See the Core Data Form instructions for more information on who should sign this form.)

Company:	Targa Gas Processing LLC	**Job Title:**	VP & Region Manager
Name *(In Print)* **:**	Clark White	**Phone:**	(713) 584-1525
Signature:	Clark White	**Date:**	2/16/2012

4. PERMIT APPLICATION FEE (TCEQ TABLE 30)

Pursuant to 30 TAC Section (§)116.141, the permit fee for a construction permit application is based on the capital cost of the proposed project. The permit fee is determined as 0.3% of the capital cost of the proposed project with a minimum fee of $900 and a maximum fee of $75,000.

The associated capital costs with this permit application are the construction of the processing plant; therefore, the maximum fee of $75,000 will be paid. TCEQ Table 30 is included at the end of this section. Targa has submitted a check in this amount to the TCEQ Revenue Section under separate cover.

Because the capital cost of the project will be more than $2,000,000, a Professional Engineer (P.E.) review has been conducted on the emission estimates and BACT analysis. The P.E. seal is included in Section 14 of this permit application.

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.state.tx.us/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	$ > $25,000,000

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: Targa Gas Processing LLC

Company Representative Name (please print): Clark White Title: VP & Region Manager

Company Representative Signature: Clark White

Estimated Capital Cost		**Permit Application Fee**	**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)**

PERMIT APPLICATION FEE (from table above) = $75,000 Date: 2/16/2012

WARNING – THIS CHECK IS PROTECTED BY SPECIAL SECURITY GUARD PROGRAM™ FEATURES

Targa Resources Partners LP
1000 Louisiana
Suite 4300
Houston, TX 77002

JPMorgan Chase Bank, N.A.
Chicago, IL

CHECK NO. 549317
CHECK DATE 01/13/2012

70-2322/719
709373500

*** Seventy Five Thousand Dollars Only*************

CHECK AMOUNT
$75,000.00

Pay To The Order Of
TEXAS COMMISSION ON ENVIRONMENTAL
QUALITY
REVENUE SECTION MC214
P O BOX 13088
AUSTIN TX 78711-3088

SECURE FEATURES INCLUDE INVISIBLE FIBERS • MICROPRINTING • VOID FEATURE PANTOGRAPH • ENDORSEMENT BACKER • BROWNSTAIN CHEMICAL REACTANT

⑈000549317⑈ ⑆071923226⑆ 709373500⑈

PAY TO:
TEXAS COMMISSION ON ENVIRONMENTAL
QUALITY
REVENUE SECTION MC214
P O BOX 13088
AUSTIN TX 78711-3088

Targa Resources Partners LP

Page 1 of 1

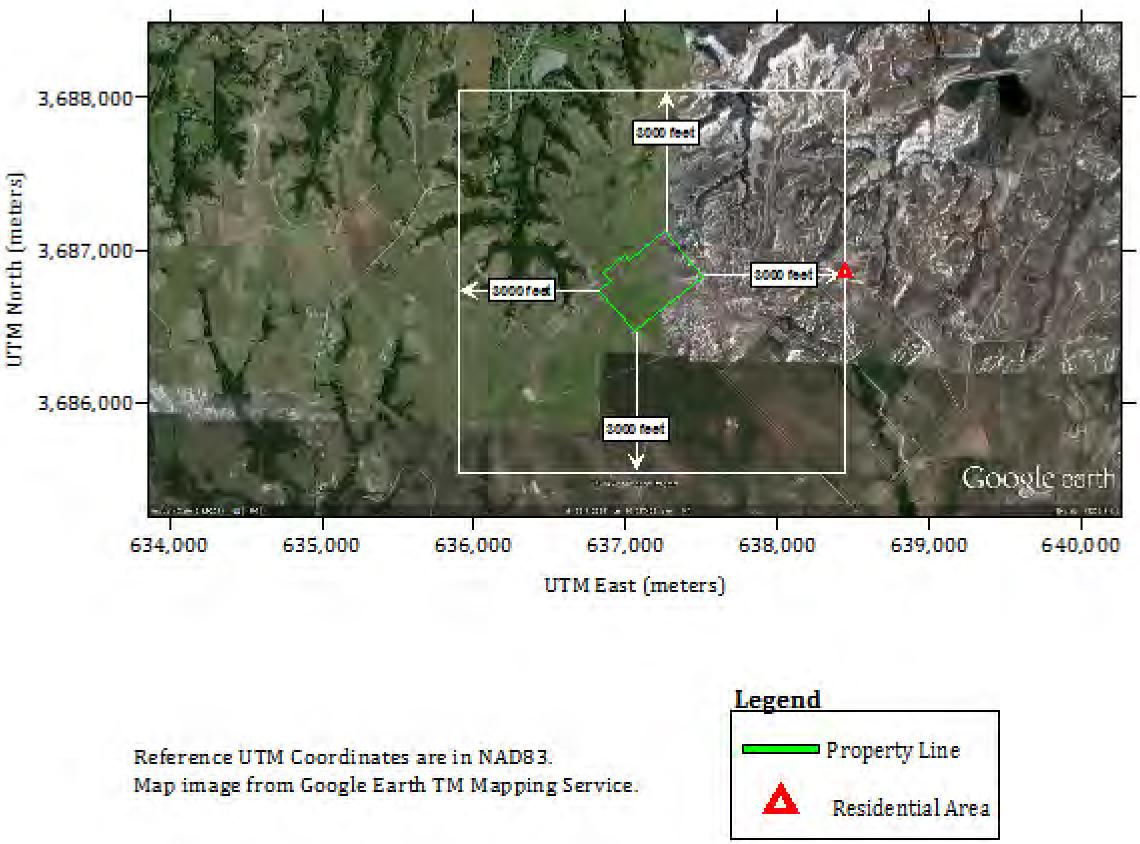
VENDOR NO.	CHECK DATE	CHECK NO	CHECK TOTAL
37856	**1/13/2012**	**549317**	**$75,000.00**

VOUCHER NUMBER	INVOICE NUMBER	INVOICE DATE		AMOUNT PAID
00196361	01112012	20120111	X JO BURNETTE	$ 75,000.00

Longhorn

The Longhorn Gas Plant is located in Wise County, Texas. An area map is included in this section to graphically depict the location of the facility with respect to the surrounding topography. Figure 4-1 is an area map centered on the Longhorn Gas Plant that extends out at least 3,000 feet from the property line in all directions. The map depicts the fenceline/property line with respect to predominant geographic features (such as highways, roads, streams, and railroads). There are no schools within 3,000 feet of the facility boundary.

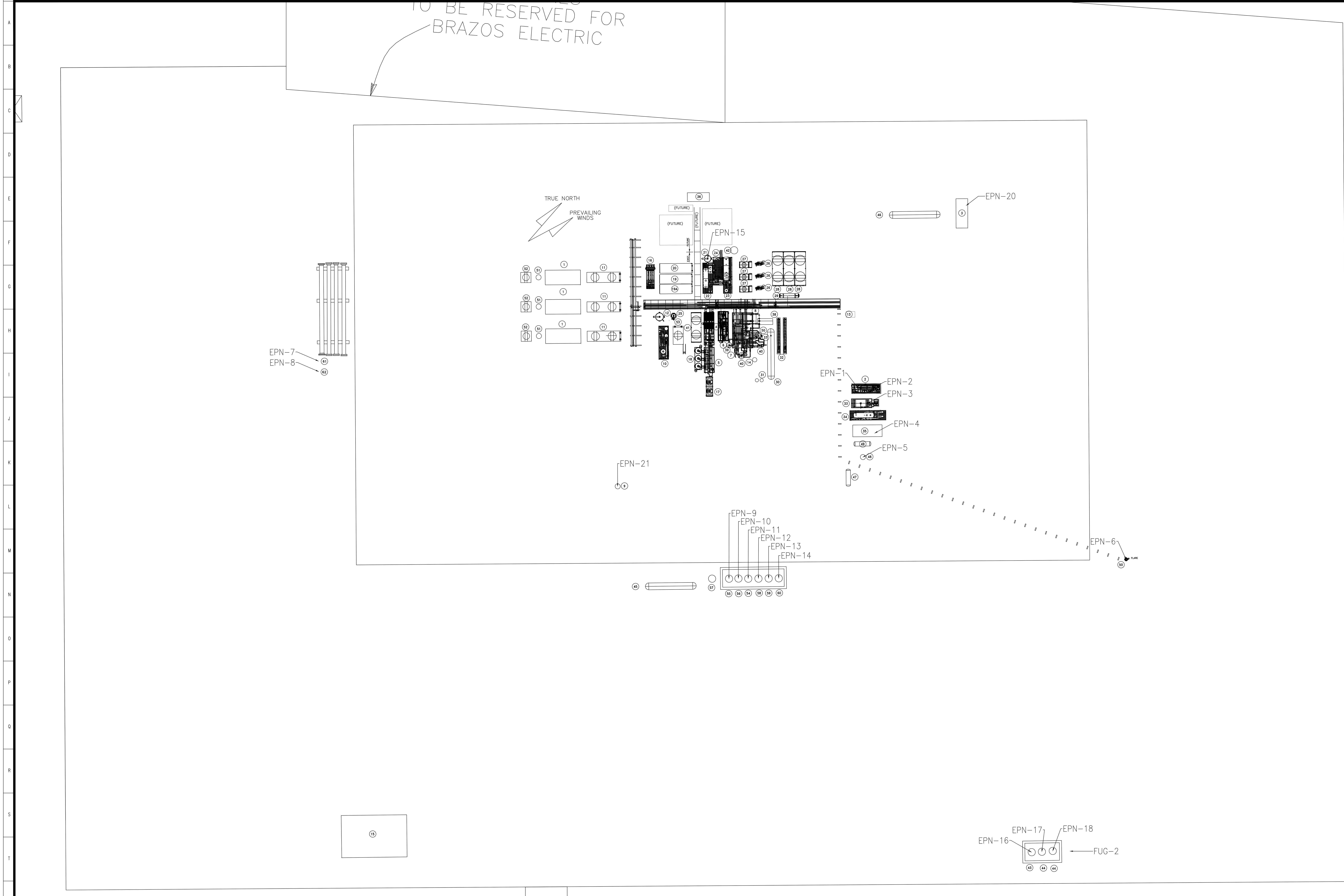
Figure 5-1
Targa Gas Processing LLC
Longhorn Plant Area Map



Reference UTM Coordinates are in NAD83.
Map image from Google Earth TM Mapping Service.

6. PLOT PLAN

The following figure depicts the site plans for the proposed Longhorn Gas Plant.



EQUIPMENT

1. RESIDUE COMPRESSOR
2. TEG REGEN SKID
3. REFRIGERANT UNLOADING
4. DEHY REGEN SKID #1
5. DEHY REGEN SKID #2
6. INLET GAS CHILLER SKID
7. PROCESS SKID #1
8. PROCESS SKID #2
9. OPEN DRAIN SUMP
10. INLET GAS SKID
11. RESIDUE COMPRESSOR COOLER
12. AMINE CONTACTOR
13. INSTRUMENT AIR COMPRESSOR
14. METHANOL STORAGE TANK
15. OFFICE/SHOP/WAREHOUSE/CONTROL ROOM
16. AMINE CIRCULATION PUMP SKID
17. REGEN GAS COOLER
18. MOL SIEVE DENY ABSORBERS
19. AMINE COOLER (3 BAYS)
20. AMINE STILL REFLUX CONDENSER
21. AMINE STILL
22. REFLUX/BOOSTER SKID
23. AMINE FILTER SKID
24. AMINE REBOILER SKID
25. GLYCOL CONTACTOR
26. REFRIG COMPRESSORS
27. LUBE OIL COOLERS
28. REFRIG CONDENSER
29. REFRIG ACCUMULATOR
30. PRODUCT SURGE TANK
31. PRODUCT BOOSTER PUMP
32. PRODUCT PIPELINE PUMP
33. REGEN GAS HEATER
34. HEAT MED PUMP SKID
35. HEAT MED HEATER
36. MCC BUILDING
37. DEMETHANIZER TOWER
38. EXPANDER/COMPRESSOR
39. COLD SEPARATOR
40. BRAZED ALUMINUM EXCHANGERS
41. BOOSTER COMPRESSOR COOLER
42. AMINE DRAIN SUMP
43. WASTEWATER TANK
44. LOW PRESSURE CONDENSATE 2-210BBLS
45. CLOSED DRAIN TANK
46. REFRIGERANT PROPANE STORAGE
47. FLARE KO DRUM
48. THERMAL OXIDIZER KNOCK OUT DRUM
49. THERMAL OXIDIZER TANK
50. FLARE STACK
51. EXHAUST SILENCER
52. AUXILIARY COOLER 14'X14'
53. TREATED FIN FAN GAS COOLER 14'X25'
54. METHANOL 1000 GALLON TANK
55. TEG 210 BBL
56. HOT OIL STORAGE 210 BBL
57. DEIONIZED WATER 210 BBL
58. AMINE STORAGE 210 BBL
59. LUBE OIL 100 BBL 3612'S
60. LUBE OIL 100 BBL SCREW
61. 16" RECEIVER
62. 12" RECEIVER

EPN-1 TEG-1 GLYCOL HEATER
EPN-2 TEG-1 STILL VENT
EPN-3 HTR-1 REGEN HEATER
EPN-4 HTR-2 HEAT MED. HEATER
EPN-5 RTO-1 REGEN THERMAL OXIDIZER
EPN-6 FLARE-1 FLARE
EPN-7 PR-1 16" RECEIVER
EPN-8 PR-2 12" RECEIVER
EPN-9 TEG TANK TEG STORAGE 210 BBL
EPN-10 HOT OIL TANK HOT OIL STORAGE 210 BBL
EPN-11 MEOH-1 METHANOL STORAGE
EPN-12 AMINE TANK AMINE STORAGE 210 BBL
EPN-13 LUBE OIL TANK-1 3612 OIL 100 BBL
EPN-14 LUBE OIL TANK-2 REF OIL 100 BBL
EPN-15 AMINE STILL VENT-1 AMINE STILL VENT
EPN-16 WASTEWATER TANK 210 BBL
EPN-17 LOW PRESSURE CONDENSATE TANK-1 210 BBL
EPN-18 LOW PRESSURE CONDENSATE TANK-2 210 BBL
FUG-2 LOW PRESSURE CONDENSATE/WASTEWATER LOADING
EPN-20 REFRIGERANT UNLOADING
EPN-21 OPEN DRAIN SUMP

REFERENCE DWGS.	REV	DESCRIPTION	DWN	CHKD	DATE	REV	DESCRIPTION	DWN	CHKD	DATE
						C	REVISED PER FIELD MARK-UPS	TRA	JEO	2/16/12
						B	MOVED TANKS	TRA	JEO	12/22/11
						A	USED PLOT PLAN AS BASE TO CREATE THIS DRAWING	TRA	JEO	12/14/11

PREPARED BY: TARGA MIDSTREAM SERVICES LLC

PROJECT NUMBER:

SCALE: 1" = 60'	DATE
DWN BY: TRA	12/14/11
CHKD BY: JEO	
FINAL CK:	
ENGR.:	
APPRV:	
APPRV:	

PLANT NAME
LONGHORN
WISE COUNTY, TX

TARGA

DRAWING NUMBER 116-100-E1
CAD FILE NAME LH100E1
REVISION 0

PLOT PLAN
EMISSION POINTS

PLOT DATE: 2/16/12

(TRA 2/16/12)

7. PROCESS DESCRIPTION & PROCESS FLOW DIAGRAM

The 200 MMscfd Longhorn Gas Plant will consist of inlet separation facilities, an amine treating unit, glycol unit, cryogenic processing skid and supporting equipment. The supporting or auxiliary equipment consists of a hot oil heater, refrigeration system, regeneration heater, residue compression, regenerative thermal oxidizer, flare, and storage and truck loading and unloading facilities for consumable chemicals. A process flow diagram is included at the end of this section.

7.1. INLET AND SEPARATION

Gas will flow into the plant from either of two delivery points through high pressure pipelines equipped with onsite pipeline pig receivers (EPN 7-MSS, EPN 8-MSS). Gas from the pig receivers flows into the inlet slug catcher for liquid removal. The gas is then measured and goes through the Plant Inlet Separator for removal of any additional water, solids or liquids. Gas then flows to the Plant Inlet Filter/Separator for filtering of smaller particles of water and solids. Condensate from all inlet separation equipment is pumped back into a pipeline for delivery and handling at an existing facility located offsite.

7.2. GAS TREATING

After inlet separation and filtration, the inlet gas flows into the Amine Contactor, where the gas is contacted with an aqueous solution of UCARSOL AP-814 amine to remove CO_2. CO_2 exits with the amine from the bottom of the contactor and is heated and regenerated using closed hot oil system in the Amine Regenerator. Hot oil is circulated and supplied by the Heating Medium Heater (EPN 4). The CO_2 released from the regeneration process is routed to the onsite Regenerative Thermal Oxidizer, (RTO, EPN 5), where the vent gas is combusted and burned. When the RTO is down for maintenance the vent gas is routed to an atmospheric vent stack (EPN 15). Treated gas (less CO_2) exits the Amine Contactor and is routed to the Treated Gas Coolers where it is cooled with ambient air. Any condensed water drops out in the Treated Gas Scrubber. Water that does not drop out is recycled back to the amine process for reuse.

7.3. GAS DEHYDRATOR

Gas from the Treated Gas Scrubber then goes to the TEG Contactor where water removal is accomplished by contacting with Triethylene Glycol (TEG). The TEG is then regenerated in a 2.0 MMBtu/hr direct fired reboiler (EPN 1). Flash vapors from this unit go through an exchanger to remove condensables and then are routed back to the reboiler burner as fuel. Water removed from the TEG in the reboiler is cooled and any residual vapors are routed to the RTO (EPN 5) for combustion. During RTO maintenance the residual vapors are vented to the atmosphere (EPN 2). Dehydrated gas leaves the contactor and is exchanged with incoming glycol in a side mounted exchanger and then routed to the Mole Sieve Inlet Separator to recover any glycol carryover. Any recovered glycol/water is recycled back to the TEG system for reuse.

Gas exits the Mole Sieve Inlet Separator and flows into the Inlet Filter / Separator where it is again filtered prior to entering the Mole Sieve Dehydrator Beds. The gas flows into two (2) of the three (3) Mole Sieve Dehydrators for removal of any traces of water prior to the cryogenic process. Each dehydrator contains molecular sieve dehydration beads that absorb trace amounts of water from the gas stream. Two vessels will be used to dehydrate inlet gas while the third vessel is being regenerated. Dehydrated high pressure gas is used for regeneration. The regeneration gas is compressed by a Sundyne Compressor. The compressed gas flows to the Regeneration Gas Heater (EPN 3). The heater duty is not a 24 hour, continuous duty operation but only needed a few hours per day per bed. The hot gas flows from the heater to the dehydrator vessel being regenerated. The water is removed from the molecular sieve by evaporation. The hot gas and vaporized water flow to the Regeneration Gas Cooler, where the gas is cooled and the water is condensed. The cool regeneration gas stream flows to the Regeneration Gas Scrubber where condensed water is level controlled to the closed drain system flash tank and then to the plant waste water tank. The cooled gas recycles to the inlet of the plant upstream of the Inlet Filter/Separator. Dehydrated gas from the mole sieve beds flows into the Mole Sieve Dust Filters to remove any mole sieve particles prior to entry into the cryogenic process.

7.4. CRYOGENIC PROCESS

Gas flow into the Cryogenic Process is split to (2) plate fin type exchangers, Normally 60% will go to the Inlet Gas Exchanger, while the remainder flows to the Gas/Product Exchanger, then the Demethanizer reboiler, and then to the Demethanizer Side Reboiler or Heater. The Exchangers are combined into one plate fin exchanger. Gas vapor and liquid from the exchangers are combined and enter the Demethanizer Tower. The inlet gas is further cooled by heat exchange with propane refrigerant in the Inlet Gas Chiller. There are (3) 1500HP electric driven screw compressors that supply the process with refrigerant propane for cooling of the gas. Any heavier components collected in the refrigeration compressor scrubbers or system goes to the closed drain system flash tank. Refrigerant propane is loaded by truck into the Refrigerant Accumulator. Vapor and liquids from the chiller then flow to the Cold Separator. The Cold Separator is used to separate vapor and liquid hydrocarbons that have condensed as a result of chilling in the exchangers. Most of the vapor exiting the Cold Separator flows into the Expander side of the Expander/Booster Compressor where the temperature and pressure are reduced and enter the Demethanizer Tower. A portion of the Cold Separator liquids combines with a portion of the Cold Separator overhead vapors and flows to the Demethanizer Feed Subcooler where it is cooled with cold residue gas. The pressure is reduced and the stream feeds the top of the Demethanizer Tower. The remainder of the Cold Separator Liquid is level controlled to reduce the pressure and enters the Demethanizer Tower.

The Demethanizer Tower is a packed tower with a bottoms reboiler and a side reboiler (also known as a side heater). Liquids leaving the bottom of the tower flow to the Product Surge Tank. The product is then pumped by the Product Booster Pumps which are tandem seal centrifugal pumps, through the Gas/Product Exchanger where the product is heated by exchange with the inlet gas and then to the Product Pipeline Pumps which are tandem seal multistage centrifugal pumps. Overhead gas vapors (residue) from the Demethanizer Tower flows to the Demethanizer Feed Subcooler, then to the Inlet Gas Exchanger where the temperature is increased by heat exchange with the inlet gas. The residue leaving this exchanger is compressed by the Booster Compressor side of the Expander/Booster Compressor. Boosted residue is cooled in the Booster Compressor After-cooler and then flows to the residue compressors. Residue compressors comprise (3)-5,000 hp electric motor-driven reciprocating compressors which take the residue gas from plant residue pressure to pipeline sales pressure. Any compressor liquids accumulated from scrubbers is routed to the closed drain system flash tank. After cooling with fin fan units the residue gas is delivered by pipeline to the sales point offsite.

7.5. CLOSED DRAIN SYSTEM

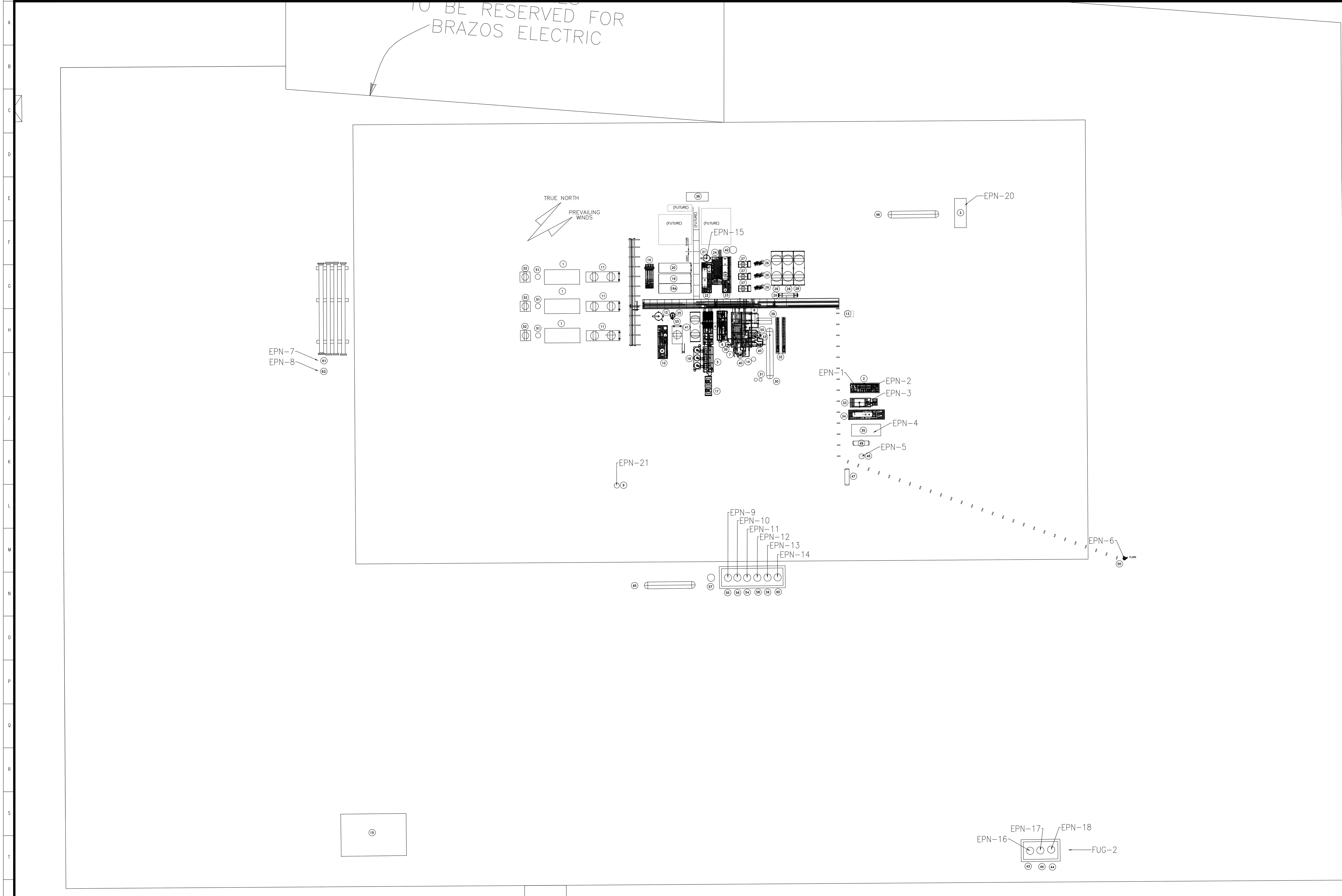
The closed drain system is designed with a flash tank that allows flash vapors to go to the plant fuel system via pressure feed or a vapor recovery unit. Liquids from the flash tank go to the low pressure condensate tanks (EPNs 17, 18). Water is separated out from the condensate and is drained to the waste water tank (EPN 16). Condensate is loaded out via trucks (FUG-2). Flash, working, and breathing vapors from the low pressure condensate tanks are controlled by the vapor recovery unit (VRU) and delivered to the plant fuel system.

7.6. OPEN DRAIN SYSTEM

The facility is equipped with an open (atmospheric) drain system to collect rain water and skid drain liquids to the open drain sump (EPN 21). The water collected in the sump flows to the waste water tank (EPN 16). Water in the waste water tank is loaded onto trucks for offsite handling.

7.7. FLARE SYSTEM

A 40 CFR §60.18 compliant flare (EPN 6) will be located on the facility site. This flare is air assisted, designed for smokeless operation. All pressure safety valves (PSV) containing heavier than air hydrocarbons, refrigeration system PSV's and compressor blowdowns and residue compressor blowdown vapors are routed to the flare.



EQUIPMENT

1. RESIDUE COMPRESSOR
2. TEG REGEN SKID
3. REFRIGERANT UNLOADING
4. DEHY REGEN SKID #1
5. DEHY REGEN SKID #2
6. INLET GAS CHILLER SKID
7. PROCESS SKID #1
8. PROCESS SKID #2
9. OPEN DRAIN SUMP
10. INLET GAS SKID
11. RESIDUE COMPRESSOR COOLER
12. AMINE CONTACTOR
13. INSTRUMENT AIR COMPRESSOR
14. METHANOL STORAGE TANK
15. OFFICE/SHOP/WAREHOUSE/CONTROL ROOM
16. AMINE CIRCULATION PUMP SKID
17. REGEN GAS COOLER
18. MOL SIEVE DENY ABSORBERS
19. AMINE COOLER (3 BAYS)
20. AMINE STILL REFLUX CONDENSER
21. AMINE STILL
22. REFLUX/BOOSTER SKID
23. AMINE FILTER SKID
24. AMINE REBOILER SKID
25. GLYCOL CONTACTOR
26. REFRIG COMPRESSORS
27. LUBE OIL COOLERS
28. REFRIG CONDENSER
29. REFRIG ACCUMULATOR
30. PRODUCT SURGE TANK
31. PRODUCT BOOSTER PUMP
32. PRODUCT PIPELINE PUMP
33. REGEN GAS HEATER
34. HEAT MED PUMP SKID
35. HEAT MED HEATER
36. MCC BUILDING
37. DEMETHANIZER TOWER
38. EXPANDER/COMPRESSOR
39. COLD SEPARATOR
40. BRAZED ALUMINUM EXCHANGERS
41. BOOSTER COMPRESSOR COOLER
42. AMINE DRAIN SUMP
43. WASTEWATER TANK
44. LOW PRESSURE CONDENSATE 2-210BBLS
45. CLOSED DRAIN TANK
46. REFRIGERANT PROPANE STORAGE
47. FLARE KO DRUM
48. THERMAL OXIDIZER KNOCK OUT DRUM
49. THERMAL OXIDIZER TANK
50. FLARE STACK
51. EXHAUST SILENCER
52. AUXILIARY COOLER 14'X14'
53. TREATED FIN FAN GAS COOLER 14'X25'
54. METHANOL 1000 GALLON TANK
55. TEG 210 BBL
56. HOT OIL STORAGE 210 BBL
57. DEIONIZED WATER 210 BBL
58. AMINE STORAGE 210 BBL
59. LUBE OIL 100 BBL 3612'S
60. LUBE OIL 100 BBL SCREW
61. 16" RECEIVER
62. 12" RECEIVER

EPN-1 TEG-1 GLYCOL HEATER
EPN-2 TEG-1 STILL VENT
EPN-3 HTR-1 REGEN HEATER
EPN-4 HTR-2 HEAT MED. HEATER
EPN-5 RTO-1 REGEN THERMAL OXIDIZER
EPN-6 FLARE-1 FLARE
EPN-7 PR-1 16" RECEIVER
EPN-8 PR-2 12" RECEIVER
EPN-9 TEG TANK TEG STORAGE 210 BBL
EPN-10 HOT OIL TANK HOT OIL STORAGE 210 BBL
EPN-11 MEOH-1 METHANOL STORAGE
EPN-12 AMINE TANK AMINE STORAGE 210 BBL
EPN-13 LUBE OIL TANK-1 3612 OIL 100 BBL
EPN-14 LUBE OIL TANK-2 REF OIL 100 BBL
EPN-15 AMINE STILL VENT-1 AMINE STILL VENT
EPN-16 WASTEWATER TANK 210 BBL
EPN-17 LOW PRESSURE CONDENSATE TANK-1 210 BBL
EPN-18 LOW PRESSURE CONDENSATE TANK-2 210 BBL
FUG-2 LOW PRESSURE CONDENSATE/WASTEWATER LOADING
EPN-20 REFRIGERANT UNLOADING
EPN-21 OPEN DRAIN SUMP

REFERENCE DWGS.	REV	DESCRIPTION	DWN	CHKD	DATE	REV	DESCRIPTION	DWN	CHKD	DATE
						C	REVISED PER FIELD MARK-UPS	TRA	JEO	2/16/12
						B	MOVED TANKS	TRA	JEO	12/22/11
						A	USED PLOT PLAN AS BASE TO CREATE THIS DRAWING	TRA	JEO	12/14/11

SCALE: 1" = 60'	DATE
DWN BY: TRA	12/14/11
CHKD BY: JEO	
FINAL CK:	
ENGR.:	
APPRV:	
APPRV:	

PREPARED BY: TARGA MIDSTREAM SERVICES LLC

PROJECT NUMBER:

PLANT NAME
LONGHORN
WISE COUNTY, TX

TARGA

PLOT PLAN
EMISSION POINTS

DRAWING NUMBER: 116-100-E1
CAD FILE NAME: LH100E1
REVISION: 0

PLOT DATE: 2/16/12

(TRA 2/16/12)

This section summarizes the criteria and hazardous air pollutant emission calculation methodologies and provides emission calculations for the emission sources at the proposed new Longhorn Gas Plant. GHG emissions are not addressed in this permit application nor are they quantified in this section.

Detailed emission calculation spreadsheets, including example calculations, are included at the end of this section. These emission estimates reflect the emission limits chosen as BACT in Section 12.

The following emission units are included in the emission calculations provided at the end of this section:

- Three natural gas heaters (EPNs 1, 3, 4);
- One amine treating unit (EPN 15);
- One TEG dehydrator (EPN 2);
- One RTO (EPN 5);
- Start-up activities from the RTO (EPN 5-MSS);
- One flare (EPN 6, 6-MSS);
- Nine storage tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18) and an open drain sump (EPN 21);
- Fugitive emissions from truck loading (EPN FUG-2);
- Fugitive emissions from piping components (EPN FUG-1); and
- Fugitive emissions from maintenance, start-up and shutdown activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS).

8.1. HEATERS

The Longhorn Gas Plant will include three natural gas-fired heaters: TEG Reboiler (EPN 1), Regeneration Heater (EPN 3), and Hot Oil Heater (EPN 4). Combustion of natural gas will result in emissions of NO_x, CO, VOC, $PM/PM_{10}/PM_{2.5}$, and SO_2.

Emissions factors for the TEG Reboiler (EPN 1) and Hot Oil Heater (EPN 4) for NO_x and CO are based on manufacturer guarantees; VOC, $PM/PM_{10}/PM_{2.5}$, and SO_2 emission factors are obtained from U.S. EPA AP-42 Section 1.4, Table 1.4-2.[5] Emission factors for the Regeneration Heater (EPN 3) for NO_x, CO, and VOC are based on manufacturer guarantees; $PM/PM_{10}/PM_{2.5}$ and SO_2 emission factors are obtained from U.S. EPA AP-42 Section 1.4, Table 1.4-2. [6]

The emission factors for VOC, $PM/PM_{10}/PM_{2.5}$, and SO_2 obtained from AP-42 Table 1.4-2 are converted from lb/MMscf of natural gas fired to lb/MMBtu heat input by dividing the emission factor by the average natural gas heating value of 1,020 Btu/scf, per AP-42 Table 1.4-2, footnote a. The emission factors also were converted to the site-specific natural gas heating value by multiplying by the ratio of the site-specific heating value to the average heating value of 1,020 Btu/scf. An example conversion calculation follows:

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[5] U.S. EPA AP-42 Section 1.4, Natural Gas Combustion from External Combustion Sources (July 1998).

[6] Ibid.

$$\text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)=\frac{\text{AP-42 Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right)}{1{,}020\left(\frac{\text{Btu}}{\text{scf}}\right)}\times\frac{\text{Site-Specific Heating Value}\left(\frac{\text{Btu}}{\text{scf}}\right)}{1{,}020\left(\frac{\text{Btu}}{\text{scf}}\right)}$$

The PM emission factor obtained from AP-42 Table 1.4-2 represents total PM (i.e., filterable plus condensable). Additionally, all PM is assumed to be less than 1.0 micrometer in diameter, according to AP-42 Table 1.4-2, footnote c. Therefore, the total PM emission factor is used to estimate total PM_{10} and total $PM_{2.5}$.

Hourly emission rates are based on the maximum heat input rating (MMBtu/hr) for each heater. Annual emission rates are based on maximum operation equivalent to 8,760 hrs/yr. The following are example calculations for hourly and annual NO_X, CO, VOC, PM/PM_{10}/$PM_{2.5}$, and SO_2 emission rates from the heaters:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)=\text{Heat Input Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right)\times\text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

$$\text{Annual Emission Rate (tpy)}=\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)\times\text{Hours of Operation}\left(\frac{\text{hr}}{\text{yr}}\right)\times\left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

8.2. AMINE TREATER

The Longhorn Gas Plant will include one amine treater (FIN 15). Emissions during normal operations from the amine still vent will be routed to the RTO (EPN 5), which has a destruction rate efficiency (DRE) of 99%. During RTO downtime, the amine emissions will be emitted directly to the atmosphere through the amine still vent (EPN 15). Emissions that occur during this alternate operating scenario are detailed in this section. A discussion of emissions that occur during normal operations when the amine still vent is routed to the RTO is located in Section 8.4.

VOC and HAP Hourly Emissions

Uncontrolled hourly VOC and HAP emissions from the amine treater that occur during RTO downtime are calculated using the ProMax® output for the waste stream. The following equation is used to estimate hourly VOC and HAP emission rates from the amine treater:

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right)=\text{ProMax Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

The ProMax® simulation output file for the amine treater is provided in Appendix A for reference.

H_2S Hourly Emissions

Uncontrolled hourly H_2S emissions are based on an estimated H_2S content of 70 ppmv or 0.007 mol % maximum. The following equation is used to estimate hourly emission rates for H_2S from the amine treater:

$$\text{Uncontrolled Hourly H}_2\text{S Emissions Rate}\left(\frac{\text{lb}}{\text{hr}}\right)$$
$$=\text{H}_2\text{S MW}\left(\frac{\text{lb}}{\text{lb}-\text{mol}}\right)\text{ x H}_2\text{S Composition (mol \%) x Waste Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right)\text{ x }\left(\frac{10^6\text{ scf}}{\text{MMscf}}\right)\text{ x }\left(\frac{1\text{ day}}{24\text{ hr}}\right)\text{ x }\left(\frac{1\text{ lb}-\text{mole}}{379.5\text{ scf}}\right)$$

Annual Emissions

Annual emission rates for uncontrolled VOC, HAP, and H_2S during RTO downtime are estimated based on the expected RTO downtime frequency and duration, as shown in the following equation:

$$\text{Uncontrolled Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Number of events per Year}\left(\frac{\text{events}}{\text{yr}}\right) \times \text{Duration of event}\left(\frac{\text{hr}}{\text{events}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

8.3. GLYCOL DEHYDRATOR

The Longhorn Gas Plant will include one TEG dehydrator (FIN 2), which has a condenser to aid in the control of emissions. Emissions during normal operations from the condenser stream will be routed to the RTO (EPN 5), which has a DRE of 99%. During RTO downtime the condenser stream emissions will be emitted directly to the atmosphere through the dehydrator vent (EPN 2). Emissions that occur during this alternate operating scenario are detailed in this section. A discussion of emissions that occur during normal operations when the condenser stream is routed to the RTO is located in Section 8.4.

VOC and HAP Hourly Emissions

Uncontrolled VOC and HAP hourly emissions from the TEG dehydrator that occur during RTO downtime are calculated using the ProMax® output for the condenser stream. The following equation is used to estimate hourly VOC and HAP emission rates from the TEG dehydrator:

$$\text{Uncontrolled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{ProMax Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

The ProMax Simulation output file for the TEG dehydrator is provided in Appendix A for reference.

H_2S Hourly Emissions

Uncontrolled hourly H_2S emissions are based on an estimated H_2S content of 70 ppmv or 0.007 mol % maximum. The following equation is used to estimate hourly emission rates for H_2S from the TEG dehydrator:

$$\text{Uncontrolled Hourly } H_2S \text{ Emissions Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = H_2S\text{ MW}\left(\frac{\text{lb}}{\text{lb}-\text{mol}}\right) \times H_2S\text{ Composition (mol \%)} \times \text{Waste Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \left(\frac{10^6\text{ scf}}{\text{MMscf}}\right) \times \left(\frac{1\text{ day}}{24\text{ hr}}\right) \times \left(\frac{1\text{ lb}-\text{mole}}{379.5\text{ scf}}\right)$$

Annual Emissions

Annual emission rates for uncontrolled VOC, HAP, and H_2S during RTO downtime are estimated based on the hourly emission rate and expected RTO downtime frequency and duration, as shown in the following equation:

$$\text{Uncontrolled Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Number of events per Year}\left(\frac{\text{events}}{\text{yr}}\right) \times \text{Duration of event}\left(\frac{\text{hr}}{\text{events}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

8.4. REGENERATIVE THERMAL OXIDIZER

The Longhorn Gas Plant will be equipped with one RTO (EPN 5) to control emissions from the amine unit and glycol dehydrator. Emissions of NO_x, CO, VOC, SO_2, H_2S, and HAPs from the RTO will result from the combustion of the amine still vent (FIN 15) and TEG dehydrator (FIN 2) waste streams. Additionally, the RTO will utilize a gas-fired burner system during startup.

8.4.1. RTO Normal Operations

Uncontrolled VOC and HAP emissions from the amine still vent and the glycol dehydrator are estimated using the ProMax® output, as discussed in Sections 8.2 and 8.3 above. The flowrates and characteristics for the amine still vent and condenser stream are also obtained from the ProMax® output. This information is used to determine controlled VOC and HAP emissions from the RTO due to the combustion of the waste gases.

Controlled H_2S and SO_2 emissions from the combustion of amine and glycol waste gases are estimated based on an H_2S content of 70 ppmv or 0.007 mol % maximum.

NO_X and CO emissions are calculated from vendor guarantee information for the RTO.

There are no particulate matter emissions associated with the RTO.

NO_x and CO Hourly Emissions

Emissions factors for NO_x and CO are based on manufacturer guarantees for the stack gas concentration. Hourly emission rates are based on the stack flowrate (lb-mol/hr), as shown in the following equation:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Stack Flowrate}\left(\frac{\text{lb-mol}}{\text{hr}}\right) \times \frac{\text{Stack Gas Concentration (ppm)}}{1{,}000{,}000} \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lb-mol}}\right)$$

H_2S, VOC, and HAP Hourly Emissions

Uncontrolled H_2S inlet to the RTO is based on an estimated H_2S content of 70 ppmv or 0.007 mol % maximum. The following equation is used to estimate the hourly inlet rate to the RTO:

$$\text{Hourly Inlet } H_2S \text{ Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = H_2S\ \text{MW}\left(\frac{\text{lb}}{\text{lb-mol}}\right) \times H_2S\ \text{Composition (mol \%)} \times \text{Gas Flowrate}\left(\frac{\text{MMscf}}{\text{day}}\right) \times \left(\frac{10^6\ \text{scf}}{\text{MMscf}}\right) \times \left(\frac{1\ \text{day}}{24\ \text{hr}}\right) \times \left(\frac{\text{lb-mol}}{379.5\ \text{scf}}\right)$$

Uncontrolled inlet hourly rates of VOC and HAP from the amine still vent and dehydrator condenser stream are obtained using the ProMax® output. The following equation is used to estimate hourly VOC and HAP inlet rates to the RTO:

$$\text{Uncontrolled Inlet Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{ProMax Output Stream Data}\left(\frac{\text{lb}}{\text{hr}}\right)$$

Controlled hourly emission rates of VOC, H_2S and HAP, as controlled by the RTO, are estimated using the inlet to RTO as calculated above and the guaranteed DRE. The following equation is used to estimate hourly VOC, H_2S, and HAP emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet to RTO}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency (\%)}]$$

<u>SO_2 Hourly Emissions</u>

SO_2 emissions are based on the conversion of sulfur during the destruction of inlet H_2S using a mass balance equation for the amount of H_2S that goes into and out of the RTO and the ratio of the molecular weights of SO_2 and H_2S. The equation is used to estimate hourly SO_2 emission rates from the controlled streams:

$$\text{Controlled Hourly SO}_2\text{ Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet H}_2\text{S to RTO}\left(\frac{\text{lb}}{\text{hr}}\right) - \text{Outlet H}_2\text{Sto RTO}\left(\frac{\text{lb}}{\text{hr}}\right) \times \left(\frac{\frac{64.06\text{ lb}}{\text{lb-mol}}}{\frac{34.08\text{ lb}}{\text{lb-mol}}}\right)$$

<u>Annual Emissions</u>

Annual emission rates of NO_x, CO, VOC, SO_2, H_2S, and HAPs are based on hourly emission rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emissions (tpy)} = \text{Hourly Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hrs}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

8.4.2. RTO Startup Operations

The RTO may periodically be shutdown for planned maintenance activities. The RTO will utilize a gas-fired burner system (EPN 5-MSS) to bring the RTO up to combustion temperature during startup. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine and dehydrator waste streams alone to support combustion. Emissions from the startup burner system will result from the combustion of pipeline quality natural gas. No emissions are expected from the RTO during shutdown or maintenance activities. Emissions from the amine and dehydrator streams during RTO downtime are addressed in Sections 8.2 and 8.3, respectively.

NO_x, CO, VOC, and SO_2 Hourly Emissions

Emission factors for NO_X and CO for the startup burner system are based on manufacturer guarantees. Hourly emission rates are based on the startup burner rating (MMBtu/hr).

Combustion emissions from VOC and SO_2 for the burner system are calculated using the emission factors from U.S. EPA AP-42 Section 1.4, Table 1.4-2.[7] The emission factors for VOC and SO_2 obtained from AP-42 Table 1.4-2 are converted from lb/MMscf of natural gas fired to lb/MMBtu heat input by dividing the emission factor by the average natural gas heating value of 1,020 Btu/scf, per AP-42 Table 1.4-2, footnote a. The emission factors also were converted to the site-specific natural gas heating value by multiplying by the ratio of the site-specific heating value to the average heating value of 1,020 Btu/scf. An example conversion calculation follows:

$$\text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) = \frac{\text{AP-42 Emission Factor}\left(\frac{\text{lb}}{\text{MMscf}}\right)}{1{,}020\left(\frac{\text{Btu}}{\text{scf}}\right)} \times \frac{\text{Site-Specific Heating Value}\left(\frac{\text{Btu}}{\text{scf}}\right)}{1{,}020\left(\frac{\text{Btu}}{\text{scf}}\right)}$$

The following equation is used to estimate hourly NO_X, CO, VOC and SO_2 emission rates from the startup burner system:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Startup Burner Rating}\left(\frac{\text{MMBtu}}{\text{hr}}\right) \times \text{Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right)$$

Annual Emissions

Annual RTO startup emissions of NO_X, CO, VOC and SO_2 are estimated based on hourly emissions and the expected startup duration frequency, as shown in the equation below:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours per Event}\left(\frac{\text{hr}}{\text{event}}\right) \times \text{Events per Year}\left(\frac{\text{event}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

8.5. FLARE

The flare (EPN 6) will be used to destroy the off-gas produced during emergency situations, pigging, and electric-driven compressor blowdowns. Emissions from emergency events are not included in this application since they are non-routine.

Emissions of NO_x, CO, VOC, SO_2, and HAPs from the flare will result from the combustion of pipeline quality natural gas in the pilot (EPN 6) and the combustion of gas vented during pigging and electric-driven compressor blowdowns (EPN 6-MSS). Emissions from pilot gas combustion are estimated using the methodologies described below, the design pilot gas flowrate, and the residue gas analysis. Emissions from combusting gas vented during pigging operations are

[7] U.S. EPA AP-42 Section 1.4, Natural Gas Combustion from External Combustion Sources (July 1998).

estimated using the expected gas volume and the inlet gas analysis. It is expected that the entire gas volume vented during pigging will be routed to the flare. However, a small portion of gas may be vented to the atmosphere, as discussed in Section 8.9. Emissions from residue compressor blowdown gas combustion are estimated using the expected blowdown gas volume and the residue gas analysis. Emissions from refrigeration compressor blowdown gas combustion are estimated using the expected blowdown gas volume and refrigerant propane composition.

NO_X and CO Hourly Emissions

Emission factors for NO_X and CO are obtained from the TCEQ guidance for flares and vapor oxidizers, Table 4.[8] The emission rates are based on the hourly gas stream heat inputs using the following equation:

$$\text{Hourly Gas Stream Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right) = \text{Hourly Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right) \times \text{ Gas Stream Heat Value}\left(\frac{\text{Btu}}{\text{scf}}\right) \times \left(\frac{\text{MMBtu}}{10^6\ \text{Btu}}\right)$$

The following equation is used to estimate hourly NO_X and CO emission rates from the pilot and MSS activities:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Flare Emission Factor}\left(\frac{\text{lb}}{\text{MMBtu}}\right) \times \text{ Hourly Gas Stream Heat Input}\left(\frac{\text{MMBtu}}{\text{hr}}\right)$$

H_2S, VOC, and HAP Hourly Emissions

Uncontrolled H_2S inlet to the flare is based on an estimated sulfur content of 2 grains / 100 scf. The following equation is used to estimate the hourly inlet rate to the flare:

$$\text{Hourly } H_2S \text{ Vented to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Sulfur Content}\left(\frac{\text{grains}}{100\ \text{scf}}\right) \times \left(\frac{\text{lb}}{7{,}000\ \text{grains}}\right) \times \text{ Hourly Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right)$$

Uncontrolled VOC and HAP inlet to the flare is based on the gas analysis and maximum hourly flowrates for each stream routed to the flare. The following equation is used to estimate the hourly inlet rate to the flare:

$$\begin{aligned}\text{Hourly Emission Rate Vented to Flare}\left(\frac{\text{lb}}{\text{hr}}\right)\\ = \text{ Maximum Hourly Flowrate}\left(\frac{\text{scf}}{\text{hr}}\right) \times \text{Composition (mol \%)} \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lb}-\text{mol}}\right)\\ \times\left(\frac{\text{lb}-\text{mol}}{379.5\ \text{scf}}\right)\end{aligned}$$

Controlled hourly emission rates of VOC, H_2S and HAP, as controlled by the flare, are estimated using the inlet to flare as calculated above and the guaranteed DRE. The following equation is used to estimate hourly VOC, H_2S, and HAP emission rates from the controlled streams:

$$\text{Controlled Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) \times [1 - \text{Destruction Rate Efficiency (\%)}]$$

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[8] TCEQ Air Permit Technical Guidance for Chemical Sources: Flares and Vapor Oxidizers (October 2000).

SO_2 Emissions

SO_2 emissions are based on the conversion of sulfur during the destruction of inlet H_2S using a mass balance equation for the amount of H_2S that goes into and out of the RTO and the ratio of the molecular weights of SO_2 and H_2S. The equation is used to estimate hourly SO_2 emission rates from the controlled streams:

$$\text{Controlled Hourly SO}_2\text{ Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Inlet H}_2\text{S to Flare}\left(\frac{\text{lb}}{\text{hr}}\right) - \text{Outlet H}_2\text{Sto Flare}\left(\frac{\text{lb}}{\text{hr}}\right) \times \left(\frac{\frac{64.06\text{ lb}}{\text{lb}-\text{mol}}}{\frac{34.08\text{ lb}}{\text{lb}-\text{mol}}}\right)$$

Annual Emissions

Annual emission rates of NO_x and CO are based on flare emission factors and annual gas stream heat input, as shown in the following equation:

$$\text{Annual Emission Rate Vented to Flare(tpy)} = \text{Annual Flowrate}\left(\frac{\text{MMscf}}{\text{yr}}\right) \times \text{Composition (mol \%)} \times \text{Molecular Weight}\left(\frac{\text{lb}}{\text{lb}-\text{mol}}\right) \times \left(\frac{\text{lb}-\text{mol}}{379.5\text{ scf}}\right) \times \left(\frac{10^6\text{ scf}}{\text{MMscf}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

Annual emission rates of VOC, SO_2, H_2S, and HAPs are based on the gas analysis and expected annual flowrates for each stream routed to the flare, as shown in the following equation:

$$\text{Annual Emissions (tpy)} = \text{Hourly Emissions}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Hours of Operation}\left(\frac{\text{hrs}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{2{,}000\text{ lb}}\right)$$

8.6. ATMOSPHERIC STORAGE TANKS

The proposed Longhorn Gas Plant includes the following tanks:

Table 8.6-1. Atmospheric Storage Tanks and Drain Sumps Located at Longhorn Gas Plant

EPN	Tank Description	Tank Size (gal)
9	TEG Tank TEG Storage 210 bbl	8,820
10	Hot Oil Tank Hot Oil Storage 210 bbl	8,820
11	MEOH-1 Methanol Storage	1,000
12	Amine Tank Amine Storage 10 bbl	420
13	Lube Oil Tank-1 3612 Oil 100 bbl	4,200
14	Lube Oil Tank-2 Ref Oil 100 bbl	4,200
16	Wastewater Tank 210 bbl	8,820
17	Low Pressure Condensate Tank-1 210 bbl	8,820
18	Low Pressure Condensate Tank-2 210 bbl	8,820
21	Open Drain Sump	-

Tanks 9, 10, 12, 13, 14 have both a low vapor pressure and low throughput. Therefore, based on engineering judgment, the emissions from these tanks are assumed negligible. The open drain sump will collect rain water and skid drain liquids, which will flow to the produced water tank (EPN 16). The contents of the open drain sump are expected to be mostly water and lube oil. Therefore, emissions from the open drain sump (EPN 21) are estimated to be 0.01 lb/hr and 0.01 tpy.

Working and breathing losses from the remaining tanks (EPNs 11, 16, 17, and 18) are estimated using the U.S. EPA TANKS 4.09d software, tank characteristics, and expected throughput. The condensate characteristics are obtained from a similar Targa site. The produced water is conservatively assumed to be 100% condensate.

Hourly tank emissions are estimated based on the maximum monthly emissions from the TANKS output. Annual tank emissions are taken directly from the TANKS output. All TANKS output reports are included in Appendix B.

8.6.1. Normal Operation

The condensate tanks (EPN 17 and EPN 18) and produced water tank (EPN 16) will operate in series to separate produced water from the condensate. A condensate-produced water mixture will exit from the different separation processes at the plant to the closed drain system at high pressure. To reduce the potential for flash emissions, Targa proposes to install a flash bullet tank to "step down" the pressure of the liquids before entering the atmospheric tank. All flash emissions will be 100% controlled by the VRU.

From the flash tank, the condensate-produced water mixture will be routed through the series of tanks. The condensate will remain in the first two tanks, while the produced water will separate from the condensate and will be stored in the last tank. The condensate tanks will operate with a residue gas blanket on them. The condensate tanks will be 100% controlled by the VRU, which will route the gas into the fuel system. The produced water tank will remain uncontrolled.

The only tank emissions resulting during normal VRU operation will consist of working and breathing losses from the methanol tank and the produced water tank. There will be no emissions from the condensate tanks during normal VRU operation.

8.6.2. VRU Downtime

During scheduled VRU downtime, there will be no filling of the condensate and produced water tanks and therefore no flash emissions. Additionally, the residue gas blanket on the condensate tanks will remain in the tanks with no working losses. As a result, there will be only breathing losses from the condensate and produced water tanks since the tanks will remain static during this time.

8.7. TRUCK LOADING LOSSES

Low pressure condensate and produced water will be loaded into tanker trucks and removed offsite (EPN FUG-2). VOC and HAP emissions will result from vapors in the tanker truck that will be displaced by the loaded liquids.

U.S. EPA AP-42 emission factors are used to estimate emissions from truck loading.[9] The loading method is submerged loading, dedicated normal service. The loading loss emission factor is calculated using the following equation:

$$L_L = \frac{12.46 \times SPM}{T}$$

where

L_L = loading loss (lb/1,000 gal loaded)
S = saturation factor (from AP-42, Section 5.2, Table 5.2-1)
P = true vapor pressure of loaded liquid (psia)
M = molecular weight of vapor (lb/lb-mol)
T = temperature of bulk liquid (°R = °F + 460)

The condensate characteristics are obtained from a similar Targa site. The produced water is conservatively assumed to be 100% condensate.

The following equations are used to estimate hourly and annual emission rates from the tank loading operations:

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{loading loss}\left(\frac{\text{lb}}{\text{1,000 gal}}\right) \times \text{Maximum Hourly Throughput}\left(\frac{\text{gal}}{\text{hr}}\right)$$

$$\text{Annual Emission Rate (tpy)} = \text{loading loss}\left(\frac{\text{lb}}{\text{1,000 gal}}\right) \times \text{Maximum Annual Throughput}\left(\frac{\text{gal}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

8.8. EQUIPMENT LEAK FUGITIVES

Process fugitive emissions of VOC result from leaking components such as valves and flanges and from sampling equipment used to evaluate the gas streams at the plant such as gas chromatographs and O_2 sensors (EPN FUG-1).

Emissions from fugitive equipment leaks are calculated using fugitive component counts for the proposed equipment at the Longhorn Gas Plant, the VOC content of each stream for which component counts are placed in service, and emission factors for each component type taken from the TCEQ Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives.[10] Targa has selected the 28 VHP Monitoring Program, and these control efficiencies are applied to the equipment leak fugitive calculations. The representative analyses used in the fugitive calculations are provided in Appendix C.

[9] Section 5.2, Transportation and Marketing of Petroleum Liquids (July 2008).

[10] TCEQ, Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

Hourly Emissions

Hourly emissions of VOC from traditional fugitive components (i.e., valves, pumps, flanges, compressors, relief valves, and connectors) are estimated using TCEQ emission factors, component counts, and the VOC content of each stream. The following equation is used to estimate hourly VOC emissions:

$$\text{Hourly Emission Rate (lb/hr)} \\ = \text{TCEQ Emission Factor} \left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{ Number of Components (\# comp)} \\ \times \text{VOC Weight Percent (\% wt)} \times \left(1 - \text{28 VHP Control Factor(\%)}\right)$$

Speciated VOC and HAP emissions from traditional fugitive components are estimated based on the total VOC emissions as estimated above and the speciated gas analysis for each stream. The following equation is used to estimate speciated VOC and HAP emissions for each compound in the stream:

$$\text{Speciated Hourly Emission Rate (lb/hr)} \\ = \text{TCEQ Emission Factor} \left(\frac{\text{lb}}{\text{hr-comp}}\right) \times \text{ Number of Components (\# comp)} \\ \times \text{Compound Weight Percent (\% wt)} \times \left(1 - \text{28 VHP Control Factor(\%)}\right)$$

Hourly emissions of VOC and HAP from O_2 sensors and gas chromatographs are estimated based on the sum of the speciated VOC and HAP compound emissions. The speciated VOC and HAP emissions are estimated based on the leak rate of the components and the speciated gas analysis for each stream, as shown in the following equation:

$$\text{Hourly Emission Rate (lb/hr)} \\ = \text{Leak Rate} \left(\frac{\text{scf}}{\text{hr}}\right) \times \text{ Compound Molecular Weight} \left(\frac{\text{lb}}{\text{lb-mol}}\right) \times \left(\frac{\text{lb} - \text{mol}}{\text{379.5 scf}}\right) \\ \times \text{Number of Components} \times \text{Compound Content (wt \%)}$$

Annual Emissions

Annual emissions are estimated based on hourly emissions rates and maximum operation equivalent to 8,760 hrs/yr, as shown in the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate} \left(\frac{\text{lb}}{\text{hr}}\right) \times \text{ Hours of Operation} \left(\frac{\text{hr}}{\text{yr}}\right) \times \left(\frac{\text{ton}}{\text{2,000 lb}}\right)$$

8.9. FUGITIVE MSS ACTIVITIES

Additional fugitive MSS activities are included in this application that may occur at the Longhorn Gas Plant. These emissions include pigging (EPNs 7-MSS, 8-MSS), meters (EPN FUG-MSS), and truck unloading of refrigerant propane (EPN 20-MSS) and will be vented directly to the atmosphere. It is expected that the entire gas volume vented during pigging will be routed to the flare. However, a small portion of gas may be vented to the atmosphere. The calculation of emissions for fugitive MSS activities is based on the frequency of the event, the event duration, the amount vented during each event, and the VOC content of the stream vented.

Hourly Emissions

The following equation is used to estimate speciated hourly VOC emission rates from the gaseous MSS activities (i.e., pigging and meters) for each compound in the stream. For events expected to last less than one hour, it is assumed that no more than one event occurs per hour. Total VOC and HAP emissions from each MSS activity are taken as the sum of the speciated VOC and HAP emission rates.

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Gas Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)} \times \text{Compound Content (mol \%)} \times \text{Compound Molecular Weight}\left(\frac{\text{lb}}{\text{lb-mol}}\right) \times \left(\frac{\text{lb-mol}}{379.5\ \text{scf}}\right)$$

The following equation is used to estimate hourly liquid propane emission rates from refrigerant propane unloading. For events expected to last less than hour in duration, it is assumed that no more than one event occurs per hour.

$$\text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) = \text{Liquid Volume per Event}\left(\frac{\text{scf}}{\text{event}}\right) \times \text{Propane Liquid Density}\left(\frac{\text{lb}}{\text{scf}}\right) \times \frac{1}{\text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right)}$$

Annual Emissions

Annual VOC emission rates from all MSS activities are estimated based on hourly emission rates, event frequency, and event duration, using the following equation:

$$\text{Annual Emission Rate (tpy)} = \text{Hourly Emission Rate}\left(\frac{\text{lb}}{\text{hr}}\right) \times \text{Event Frequency}\left(\frac{\text{event}}{\text{yr}}\right) \times \text{Event Duration}\left(\frac{\text{hr}}{\text{event}}\right) \times \left(\frac{\text{ton}}{2{,}000\ \text{lb}}\right)$$

Site-Wide Emission Summary for Criteria Pollutants

Normal Operations Summary

EPN	FIN	Description	Hourly Emissions (lb/hr)								
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	H_2S	HAPs
1	1	TEG-1 Glycol Reboiler	0.22	0.12	0.01	0.01	0.01	0.01	1.00E-03	--	--
2	2	TEG Dehydrator During RTO Downtime	--	--	54.66	--	--	--	--	0.10	17.52
3	3	HTR-1 Regen Heater	1.24	0.92	1.74	0.09	0.09	0.09	0.01	--	--
4	4	HTR-2 Hot Oil Heater	4.90	7.25	0.52	0.72	0.72	0.72	0.06	--	--
5	2, 15	RTO-1 Regen Thermal Oxidizer	0.11	3.32	0.73	--	--	--	3.00	0.02	0.29
6	6	Flare-1 Flare (Pilot)	0.02	0.04	1.39E-04	--	--	--	7.89E-04	8.57E-06	--
11	11	MEOH-1 Methanol Storage	--	--	0.03	--	--	--	--	--	--
15	15	Amine Still Vent During RTO Downtime	--	--	18.54	--	--	--	--	1.51	11.35
16	16	Produced Water Tank 210 bbl	--	--	0.40	--	--	--	--	--	6.64E-03
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	0.11	--	--	--	--	--	1.67E-03
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	0.11	--	--	--	--	--	1.67E-03
21	21	Open Drain Sump	--	--	0.01	--	--	--	--	--	--
FUG-1	FUG-1	Plant-wide Fugitive Components	--	--	1.16	--	--	--	--	--	0.05
FUG-2	FUG-2	Truck Loading	--	--	70.22	--	--	--	--	--	4.67
		Total Normal Operations Emissions	**6.49**	**11.65**	**148.25**	**0.82**	**0.82**	**0.82**	**3.07**	**1.63**	**33.89**

MSS Operations Summary [1]

EPN	FIN	Description	Hourly Emissions (lb/hr)								
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	H_2S	HAPs
5-MSS	5-MSS	RTO-1 Startup	0.45	0.45	0.02	--	--	--	1.73E-03	--	--
6-MSS	6-MSS	Flare-1 Flare MSS	1.79	3.58	13.99	--	--	--	0.03	3.43E-04	6.20E-03
7-MSS	7-MSS	PR-1 16" Reciever	--	--	1.06	--	--	--	--	--	0.03
8-MSS	8-MSS	PR-2 12" Reciever	--	--	1.06	--	--	--	--	--	0.03
20-MSS	20-MSS	Refrigerant Unloading	--	--	0.17	--	--	--	--	--	--
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	--	--	1.66	--	--	--	--	--	0.05
		Total MSS Emissions	**2.24**	**4.03**	**17.95**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**0.03**	**3.43E-04**	**0.12**

[1] FUG-MSS does not include pigging or refrigerant unloading since those activities have separate EPNs.

Total Site-wide Summary

Description	Hourly Emissions (lb/hr) [1]								
	NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	H_2S	HAPs
Total Site-wide Emissions	6.49	11.65	148.25	0.82	0.82	0.82	3.07	1.63	33.89
MSS Activities	2.24	4.03	17.95	0.00E+00	0.00E+00	0.00E+00	0.03	3.43E-04	0.12
Total Site-wide Emissions	**17.36**	**28.05**	**420.23**	**1.64**	**1.64**	**1.64**	**3.21**	**4.75**	**83.76**

[1] Some MSS emissions may occur at the same time as normal operation. For example, RTO startup (EPN 5-MSS) does not occur at the same time as RTO normal operation (EPN 5). In these cases, the total hourly emissions are calculated based on the maximum emission rates between MSS and normal operation scenarios.

Site-Wide Emission Summary for Criteria Pollutants

Normal Operations Summary

EPN	FIN	Description	Annual Emissions (tpy) NO$_x$	CO	VOC	PM	PM$_{10}$	PM$_{2.5}$	SO$_2$	H$_2$S	HAPs
1	1	TEG-1 Glycol Reboiler	0.96	0.53	0.04	0.04	0.04	0.04	4.00E-03	--	--
2	2	TEG Dehydrator During RTO Downtime	--	--	4.15	--	--	--	--	7.96E-03	1.33
3	3	HTR-1 Regen Heater	5.43	4.03	7.62	0.39	0.39	0.39	0.04	--	--
4	4	HTR-2 Hot Oil Heater	21.46	31.76	2.28	3.15	3.15	3.15	0.25	--	--
5	2, 15	RTO-1 Regen Thermal Oxidizer	0.48	14.55	3.21	--	--	--	13.16	0.07	1.26
6	6	Flare-1 Flare (Pilot)	0.09	0.18	6.09E-04	--	--	--	3.46E-03	3.75E-05	--
11	11	MEOH-1 Methanol Storage	--	--	0.06	--	--	--	--	--	--
15	15	Amine Still Vent During RTO Downtime	--	--	1.41	--	--	--	--	0.11	0.86
16	16	Produced Water Tank 210 bbl	--	--	1.12	--	--	--	--	--	0.03
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	0.02	--	--	--	--	--	2.41E-04
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	0.02	--	--	--	--	--	2.41E-04
21	21	Open Drain Sump	--	--	0.01	--	--	--	--	--	--
FUG-1	FUG-1	Plant-wide Fugitive Components	--	--	5.09	--	--	--	--	--	0.21
FUG-2	FUG-2	Truck Loading	--	--	1.17	--	--	--	--	--	0.08
		Total Normal Operations Emissions	**28.42**	**51.05**	**26.19**	**3.58**	**3.58**	**3.58**	**13.45**	**0.19**	**3.78**

MSS Operations Summary [1]

EPN	FIN	Description	Annual Emissions (tpy) NO$_x$	CO	VOC	PM	PM$_{10}$	PM$_{2.5}$	SO$_2$	H$_2$S	HAPs
5-MSS	5-MSS	RTO-1 Startup	1.80E-03	1.80E-03	6.34E-05	--	--	--	6.92E-06	--	--
6-MSS	6-MSS	Flare-1 Flare MSS	6.07E-03	0.01	0.30	--	--	--	4.74E-05	5.14E-07	8.06E-03
7-MSS	7-MSS	PR-1 16" Reciever	--	--	0.03	--	--	--	--	--	8.06E-04
8-MSS	8-MSS	PR-2 12" Reciever	--	--	0.03	--	--	--	--	--	8.06E-04
20-MSS	20-MSS	Refrigerant Unloading	--	--	2.07E-03	--	--	--	--	--	--
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	--	--	0.02	--	--	--	--	--	5.84E-04
		Total MSS Emissions	**7.87E-03**	**0.01**	**0.37**	**0.00E+00**	**0.00E+00**	**0.00E+00**	**5.43E-05**	**5.14E-07**	**0.01**

[1] FUG-MSS does not include pigging or refrigerant unloading since those activities have separate EPNs.

Total Site-wide Summary

Description	Annual Emissions (tpy) NO$_x$	CO	VOC	PM	PM$_{10}$	PM$_{2.5}$	SO$_2$	H$_2$S	HAPs
Total Site-wide Emissions	28.42	51.05	26.19	3.58	3.58	3.58	13.45	0.19	3.78
MSS Activities	7.87E-03	0.01	0.37	0.00E+00	0.00E+00	0.00E+00	5.43E-05	5.14E-07	0.01
Total Site-wide Emissions	**28.43**	**51.06**	**26.56**	**3.58**	**3.58**	**3.58**	**13.45**	**0.19**	**3.79**

Site-Wide Emission Summary for Hazardous Air Pollutants

Normal Operations Summary

EPN	FIN	Description	Hourly Emissions (lb/hr)						Annual Emissions (tpy)					
			Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total	Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total
1	1	TEG-1 Glycol Reboiler	--	--	--	--	--	--	--	--	--	--	--	--
2	2	TEG Dehydrator During RTO Downtime	4.66	7.42	0.39	1.76	3.30	17.52	0.35	0.56	0.03	0.13	0.25	1.33
3	3	HTR-1 Regen Heater	--	--	--	--	--	--	--	--	--	--	--	--
4	4	HTR-2 Hot Oil Heater	--	--	--	--	--	--	--	--	--	--	--	--
5	2, 15	RTO-1 Regen Thermal Oxidizer	0.10	0.12	5.53E-03	0.03	0.03	0.29	0.43	0.54	0.02	0.12	0.15	1.26
6	6	Flare-1 Flare (Pilot)	--	--	--	--	--	--	--	--	--	--	--	--
11	11	MEOH-1 Methanol Storage	--	--	--	--	--	--	--	--	--	--	--	--
15	15	Amine Still Vent During RTO Downtime	5.13	5.01	0.16	1.00	0.05	11.35	0.39	0.38	0.01	0.08	3.54E-03	0.86
16	16	Produced Water Tank 210 bbl	1.80E-03	4.01E-03	4.03E-05	7.93E-04	--	6.64E-03	4.88E-03	0.02	9.50E-05	2.02E-03	--	0.03
17	17	LP Condensate Tank 1 (During VRU Downtime)	5.13E-04	1.14E-03	1.04E-05	1.04E-05	--	1.67E-03	7.39E-05	1.64E-04	1.50E-06	1.50E-06	--	2.41E-04
18	18	LP Condensate Tank 2 (During VRU Downtime)	5.13E-04	1.14E-03	1.04E-05	1.04E-05	--	1.67E-03	7.39E-05	1.64E-04	1.50E-06	1.50E-06	--	2.41E-04
21	21	Open Drain Sump	--	--	--	--	--	--	--	--	--	--	--	--
FUG-1	FUG-1	Plant-wide Fugitive Components	3.16E-03	0.02	3.60E-04	9.73E-03	0.02	0.05	0.01	0.07	1.58E-03	0.04	0.09	0.21
FUG-2	FUG-2	Truck Loading	0.35	2.56	0.07	1.69	--	4.67	5.87E-03	0.04	1.09E-03	0.03	--	0.08
		Total Normal Operations Emissions	**10.24**	**15.14**	**0.62**	**4.49**	**3.40**	**33.89**	**1.20**	**1.62**	**0.07**	**0.40**	**0.49**	**3.78**

MSS Operations Summary [1]

EPN	FIN	Description	Hourly Emissions (lb/hr)						Annual Emissions (tpy)					
			Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total	Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total
5-MSS	5-MSS	RTO-1 Startup	--	--	--	--	--	--	--	--	--	--	--	--
6-MSS	6-MSS	Flare-1 Flare MSS	3.32E-04	3.92E-04	--	1.13E-04	5.36E-03	6.20E-03	4.32E-04	5.10E-04	--	1.47E-04	6.97E-03	8.06E-03
7-MSS	7-MSS	PR-1 16" Reciever	1.66E-03	1.96E-03	--	5.65E-04	0.03	0.03	4.32E-05	5.10E-05	--	1.47E-05	6.97E-04	8.06E-04
8-MSS	8-MSS	PR-2 12" Reciever	1.66E-03	1.96E-03	--	5.65E-04	0.03	0.03	4.32E-05	5.10E-05	--	1.47E-05	6.97E-04	8.06E-04
20-MSS	20-MSS	Refrigerant Unloading	--	--	--	--	--	--	--	--	--	--	--	--
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	2.61E-03	3.08E-03	--	8.87E-04	0.04	0.05	3.13E-05	3.69E-05	--	1.06E-05	5.05E-04	5.84E-04
		Total Site-wide MSS Emissions	**6.27E-03**	**7.39E-03**	**0.00E+00**	**2.13E-03**	**0.10**	**0.12**	**5.50E-04**	**6.49E-04**	**0.00E+00**	**1.87E-04**	**8.87E-03**	**0.01**

[1] FUG-MSS does not include pigging or refrigerant unloading since those activities have separate EPNs.

Total Site-wide Summary

Description	Hourly Emissions (lb/hr) [1]						Annual Emissions (tpy)					
	Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total	Benzene	Toluene	E-Benzene	Xylene	N-Hexane	Total
Normal Operations	10.24	15.14	0.62	4.49	3.40	33.89	1.20	1.62	0.07	0.40	0.49	3.78
MSS Activities	6.27E-03	7.39E-03	0.00E+00	2.13E-03	0.10	0.12	5.50E-04	6.49E-04	0.00E+00	1.87E-04	8.87E-03	0.01
Total Site-wide HAP Emissions	**25.88**	**37.76**	**1.47**	**11.67**	**6.99**	**83.76**	**1.20**	**1.62**	**0.07**	**0.40**	**0.50**	**3.79**

[1] Some MSS emissions may occur at the same time as normal operation. For example, RTO startup (EPN 5-MSS) does not occur at the same time as RTO normal operation (EPN 5). In these cases, the total hourly emissions are calculated based on the maximum emission rates between MSS and normal operation scenarios.

Natural Gas External Combustion Units (EPNs 1, 3, 4)

Input Data

Heating Value of Natural Gas (Btu/scf)	1,000
Hours of Operation (hrs/yr)	8,760

Natural Gas External Combustion Criteria Pollutant Emission Factors

Description	EPN	Pollutant	Emission Factor (lb/MMscf)	Emission Factor [1] (lb/MMBtu)	Source [2]
TEG-1 Glycol Reboiler	1	NO_x	--	0.11	Manufacturer Data
		CO	--	0.06	Manufacturer Data
		VOC	5.5	0.0053	AP-42, Section 1.4
HTR-1 Regen Heater	3	NO_x	--	0.1	Manufacturer Data
		CO	--	0.074	Manufacturer Data
		VOC	--	0.14	Manufacturer Data
HTR-2 Hot Oil Heater	4	NO_x	--	0.050	Manufacturer Data
		CO	--	0.074	Manufacturer Data
		VOC	5.5	0.0053	AP-42, Section 1.4
	All Heaters	PM, PM_{10}, $PM_{2.5}$ [3]	7.6	0.0073	AP-42, Section 1.4
		SO_2	0.6	0.0006	AP-42, Section 1.4

[1] AP-42 emission factors are converted to heat input rating by dividing by the average heating value (1,020 scf/Btu) and converted to the site-specific heating value by multiplying the emission factor by the ratio of the site-specific to average heating value per AP-42, Table 1-4-1, footnote a.

[2] Emission factors are taken from AP-42, Section 1.4, Table 1.4-2 (7/98).

[3] All particulate matter is conservatively assumed to be less than 1 μm per AP-42, Table 1.4-1, footnote c.

Natural Gas External Combustion Criteria Emission Rates [1, 2]

Description	EPN	Heat Input Rating (MMBtu/hr)	NO_x Hourly (lb/hr)	NO_x Annual (tpy)	CO Hourly (lb/hr)	CO Annual (tpy)	VOC Hourly (lb/hr)	VOC Annual (tpy)	$PM/PM_{10}/PM_{2.5}$ Hourly (lb/hr)	$PM/PM_{10}/PM_{2.5}$ Annual (tpy)	SO_2 Hourly (lb/hr)	SO_2 Annual (tpy)
TEG-1 Glycol Reboiler	1	2.0	0.22	0.96	0.12	0.53	0.01	0.04	0.01	0.04	1.00E-03	4.00E-03
HTR-1 Regen Heater	3	12.4	1.24	5.43	0.92	4.03	1.74	7.62	0.09	0.39	0.01	0.04
HTR-2 Hot Oil Heater	4	98.0	4.90	21.46	7.25	31.76	0.52	2.28	0.72	3.15	0.06	0.25
		Total Emissions	**6.36**	**27.85**	**8.29**	**36.32**	**2.27**	**9.94**	**0.82**	**3.58**	**0.07**	**0.29**

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Heat Input Rating (MMBtu/hr) x Emission Factor (lb/MMBtu)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{2.0\text{ MMBtu}}{\text{hr}} \cdot \frac{0.11\text{ lb}}{\text{MMBtu}} = \frac{0.22\text{ lb}}{\text{hr}}$$

[2] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.22\text{ lb}}{\text{hr}} \cdot \frac{8{,}760\text{ hr}}{\text{yr}} \cdot \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.96\text{ ton}}{\text{yr}}$$

RTO (EPNs 5, 5-MSS)

RTO Criteria Pollutant Summary [1]

Description	EPN	NO_x Hourly (lb/hr)	NO_x Annual (tpy)	CO Hourly (lb/hr)	CO Annual (tpy)	VOC Hourly (lb/hr)	VOC Annual (tpy)	SO_2 Hourly (lb/hr)	SO_2 Annual (tpy)	H_2S Hourly (lb/hr)	H_2S Annual (tpy)	HAP Hourly (lb/hr)	HAP Annual (tpy)
RTO - Normal Operation	5	0.11	0.48	3.32	14.55	0.73	3.21	3.00	13.16	0.02	0.07	0.29	1.26
RTO - Startup	5-MSS	0.45	1.80E-03	0.45	1.80E-03	0.02	6.34E-05	1.73E-03	6.92E-06	--	--	--	--
	Total	0.56	0.48	3.77	14.55	0.75	3.21	3.01	13.16	0.02	0.07	0.29	1.26

[1] Total RTO emissions based on emission estimates for each inlet stream to RTO.

RTO (EPNs 5, 5-MSS)

RTO Emissions - NO_x and CO

Input Data

Maximum Stack Flowrate [1, 2] =	15,000	scfm
	900,000	scf/hr
	2,372	lb-mol/hr
Heating Value of Natural Gas =	1,000	Btu/scf
Hours of Operation =	8,760	hrs/yr

Compound	Stack Gas Concentration (ppmvd)	Molecular Weight (lb/lb-mol)	Source	RTO Emissions [4, 5]	
				(lb/hr)	(tpy)
NO_x	1.0	46.0	Manufacturer's Data [3]	0.11	0.48
CO	50.0	28.0	Manufacturer's Data [3]	3.32	14.55

[1] Maximum stack flowrate during normal operation per manufacturer.

[2] Stack flowrate (lb-mol/hr) = Pressure (atm) x Stack flowrate (scf/hr) / Gas constant (ft^3 x atm / R / lb-mol) / Temperature (R)

$$\text{Stack flowrate (lb-mol/hr)} = \frac{1.0\text{ atm}}{} \Big| \frac{900{,}000\text{ scf}}{\text{hr}} \Big| \frac{\text{R x lb-mol}}{0.730241\text{ ft}^3\text{ x atm}} \Big| \frac{1}{520\text{ R}} = \frac{2{,}372\text{ lb-mol}}{\text{hr}}$$

[3] The stack gas concentration is provided by the manufacturer for NO_x and CO.

[4] Maximum Potential Hourly Emission Rate (lb/hr) = Stack flowrate (lb-mol/hr) x Stack Gas Concentration (ppm) / 1,000,000 x Molecular Weight (lb/lb-mol)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{2{,}372\text{ lb-mol}}{\text{hr}} \Big| \frac{1.0\text{ ppmvd}}{1{,}000{,}000} \Big| \frac{46.0\text{ lb}}{\text{lb-mol}} = \frac{0.11\text{ lb}}{\text{hr}}$$

[5] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.11\text{ lb}}{\text{hr}} \Big| \frac{8{,}760\text{ hr}}{\text{yr}} \Big| \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.48\text{ ton}}{\text{yr}}$$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Amine Acid Gas Combustion

Input Data

Maximum Amine Acid Gas Flowrate [1] =	5.76	MMscfd (wet)
Hours of Operation =	8,760	hrs/yr

Compound	Composition [1] (mol %)	DRE [2] (%)	Inlet to RTO [3, 4, 6] (lb/hr)	Inlet to RTO [3, 4, 6] (tpy)	Controlled RTO Emissions [5, 6] (lb/hr)	Controlled RTO Emissions [5, 6] (tpy)
Propane	0.01608316	99%	4.49	19.65	0.04	0.20
i-Butane	0.00112021	99%	0.41	1.80	4.12E-03	0.02
n-Butane	0.00454635	99%	1.67	7.32	0.02	0.07
i-Pentane	0.00027477	99%	0.13	0.55	1.25E-03	5.49E-03
n-Pentane	0.00047104	99%	0.22	0.94	2.15E-03	9.42E-03
n-Hexane	0.00008537	99%	0.05	0.20	4.65E-04	2.04E-03
MDEA	0.00000001	99%	1.13E-05	4.95E-05	1.13E-07	4.95E-07
Piperazine	0.00000001	99%	2.76E-06	1.21E-05	2.76E-08	1.21E-07
Benzene	0.01037536	99%	5.13	22.46	0.05	0.22
Cyclohexane	0.00047987	99%	0.26	1.12	2.56E-03	0.01
iC7	0.00001886	99%	0.01	0.05	1.20E-04	5.24E-04
nC7	0.00000502	99%	3.18E-03	0.01	3.18E-05	1.39E-04
Toluene	0.00859850	99%	5.01	21.96	0.05	0.22
iC8	0.00000326	99%	2.35E-03	0.01	2.35E-05	1.03E-04
nC8	0.00000040	99%	2.92E-04	1.28E-03	2.92E-06	1.28E-05
Ethylbenzene	0.00024043	99%	0.16	0.71	1.62E-03	7.07E-03
p-Xylene	0.00149297	99%	1.00	4.39	0.01	0.04
Isononane	0.00000187	99%	1.52E-03	6.66E-03	1.52E-05	6.66E-05
nC9	0.00000092	99%	7.47E-04	3.27E-03	7.47E-06	3.27E-05
Decane	0.00000129	99%	1.16E-03	5.08E-03	1.16E-05	5.08E-05
Hydrogen Sulfide	0.00700000	99%	1.51	6.61	0.02	0.07
VOC [7]	0.04	--	18.54	81.21	0.19	0.81
HAP [8]	0.02	--	11.35	49.72	0.11	0.50
SO_2 [9]	--	--	--	--	2.81	12.30

[1] Maximum amine acid gas flowrate and composition data based on amine acid gas stream from ProMax output data.
H_2S content estimated as 70 ppmv or 0.007 mol % maximum.

[2] Destruction efficiency per manufacturer.

[3] Hourly inlet to RTO based on amine acid gas stream from ProMax output data.

[4] Hourly H_2S Inlet to RTO (lb/hr) = H_2S MW (lb/lb-mol) x H_2S Composition (mol %) x Waste Gas Flowrate (MMscf/day) x (10^6 scf / 1 MMscf) x (1 day / 24 hr) x (1 lb-mol / 379.5 scf)

$$H_2S\text{ Inlet (lb/hr)} = \frac{34.08\text{ lb}}{\text{lb-mol}} \;\Big|\; 0.007\ \% \;\Big|\; \frac{5.76\text{ MMscf}}{\text{day}} \;\Big|\; \frac{10^6\text{ scf}}{1\text{ MMscf}} \;\Big|\; \frac{1\text{ day}}{24\text{ hr}} \;\Big|\; \frac{1\text{ lb-mol}}{379.5\text{ scf}} = \frac{1.51\text{ lb}}{\text{hr}}$$

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

$$\text{Example Controlled Propane Hourly Emission Rate (lb/hr)} = \frac{4.49\text{ lb}}{\text{hr}} \;\Big|\; (1 - 0.99\%\ ) = \frac{0.04\text{ lb}}{\text{hr}}$$

[6] Inlet to RTO and Controlled RTO Maximum Potential Annual Rate (tpy) = Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

$$\text{Example Controlled Propane Annual Emission Rate (tpy)} = \frac{0.04\text{ lb}}{\text{hr}} \;\Big|\; \frac{8{,}760\text{ hr}}{\text{yr}} \;\Big|\; \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.20\text{ ton}}{\text{yr}}$$

[7] Total VOC taken as the sum of NMNEHC.

[8] Total HAP taken as the sum of all hazardous air pollutants.

[9] Controlled RTO SO_2 Emission Rate (lb/hr) = [H_2S Inlet (lb/hr) - H_2S Outlet (lb/hr)] x SO_2 MW (lb/lb-mol) / H_2S MW (lb/lb-mol)

$$\text{Controlled } SO_2\text{ Hourly Emission Rate (lb/hr)} = \frac{[1.51 - 0.02]\text{ lb}}{\text{hr}} \;\Big|\; \frac{64.06\text{ lb/lb-mol}}{34.08\text{ lb/lb-mol}} = \frac{2.81\text{ lb}}{\text{hr}}$$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Dehydrator Waste Gas Combustion

<u>Input Data</u>

Maximum Dehydrator Waste Gas Flowrate [1] = 0.40 MMscfd (wet)

Hours of Operation = 8,760 hrs/yr

Compound	Composition [1]	DRE [2]	Inlet to RTO [3, 4, 6]		Controlled RTO Emissions [5, 6]	
	(mol %)	(%)	(lb/hr)	(tpy)	(lb/hr)	(tpy)
Propane	0.45586158	99%	8.83	38.67	0.09	0.39
i-Butane	0.06606409	99%	1.69	7.39	0.02	0.07
n-Butane	0.24559984	99%	6.27	27.46	0.06	0.27
i-Pentane	0.12113445	99%	3.84	16.81	0.04	0.17
n-Pentane	0.16780609	99%	5.32	23.29	0.05	0.23
n-Hexane	0.08711980	99%	3.30	14.44	0.03	0.14
Triethylene Glycol	0.00007432	99%	4.90E-03	0.02	4.90E-05	2.15E-04
Benzene	0.13569049	99%	4.66	20.39	0.05	0.20
Cyclohexane	0.07006450	99%	2.59	11.34	0.03	0.11
iC7	0.10266668	99%	4.52	19.79	0.05	0.20
nC7	0.03524518	99%	1.55	6.79	0.02	0.07
Toluene	0.18334286	99%	7.42	32.50	0.07	0.32
iC8	0.02317373	99%	1.16	5.09	0.01	0.05
nC8	0.00355417	99%	0.18	0.78	1.78E-03	7.81E-03
Ethylbenzene	0.00839197	99%	0.39	1.71	3.91E-03	0.02
p-Xylene	0.03776852	99%	1.76	7.71	0.02	0.08
Isononane	0.01081312	99%	0.61	2.67	6.09E-03	0.03
nC9	0.00195458	99%	0.11	0.48	1.10E-03	4.82E-03
Decane	0.00755507	99%	0.47	2.07	4.72E-03	0.02
Hydrogen Sulfide	0.00700000	99%	0.10	0.46	1.05E-03	4.59E-03
VOC [7]	1.76	--	54.66	239.42	0.55	2.39
HAP [8]	0.45	--	17.52	76.76	0.18	0.77
SO_2 [9]	--	--	--	--	0.19	0.85

[1] Maximum dehydrator waste gas flowrate and composition data based on dehydrator condenser outlet stream from ProMax output data. H_2S content estimated as 70 ppmv or 0.007 mol % maximum.

[2] Destruction efficiency per manufacturer.

[3] Hourly inlet to RTO based on dehydrator condenser outlet stream from ProMax output data.

[4] Hourly H_2S Inlet to RTO (lb/hr) = H_2S MW (lb/lb-mol) x H_2S Composition (mol %) x Waste Gas Flowrate (MMscf/day) x (10^6 scf / 1 MMscf) x (1 day / 24 hr) x (1 lb-mol / 379.5 scf)

$$H_2S\ \text{Inlet (lb/hr)} = \frac{34.08\ \text{lb}}{\text{lb-mol}} \times 0.007\ \% \times \frac{0.40\ \text{MMscf}}{\text{day}} \times \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \times \frac{1\ \text{day}}{24\ \text{hr}} \times \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} = \frac{0.10\ \text{lb}}{\text{hr}}$$

[5] Controlled RTO Maximum Potential Hourly Emission Rate (lb/hr) = Inlet to RTO (lb/hr) x (1 - DRE)

$$\text{Example Controlled Propane Hourly Emission Rate (lb/hr)} = \frac{8.83\ \text{lb}}{\text{hr}} \times (1 - 0.99\%\ ) = \frac{0.09\ \text{lb}}{\text{hr}}$$

[6] Inlet to RTO and Controlled RTO Maximum Potential Annual Rate (tpy) = Hourly Rate (lb/hr) x Hours of Operation (hr/yr) x (1 ton / 2,000 lb)

$$\text{Example Controlled Propane Annual Emission Rate (tpy)} = \frac{0.09\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{0.39\ \text{ton}}{\text{yr}}$$

[7] Total VOC taken as the sum of NMNEHC.

[8] Total HAP taken as the sum of all hazardous air pollutants.

[9] Controlled RTO SO_2 Emission Rate (lb/hr) = [H_2S Inlet (lb/hr) - H_2S Outlet (lb/hr)] x SO_2 MW (lb/lb-mol) / H_2S MW (lb/lb-mol)

$$\text{Controlled } SO_2 \text{ Hourly Emission Rate (lb/hr)} = \frac{[0.10 - 0.00]\ \text{lb}}{\text{hr}} \times \frac{64.06\ \text{lb/lb-mol}}{34.08\ \text{lb/lb-mol}} = \frac{0.19\ \text{lb}}{\text{hr}}$$

RTO (EPNs 5, 5-MSS)

RTO Emissions - Startup [1]

Input Data

Startup Burner Size =	3	MMBtu/hr
Heating Value of Natural Gas =	1,000	Btu/scf
Fuel Gas Flowrate =	3,000	scf/hr
Startup Event Duration =	2	hr/event
Startup Event Frequency =	4	events/yr

Pollutant	Emission Factor (lb/MMscf)	Emission Factor (lb/MMBtu) [2]	Emission Factor (grains/100 scf)	Source
NO_x	--	0.15	--	Manufacturer's Data [3]
CO	--	0.15	--	Manufacturer's Data [3]
VOC	5.5	5.29E-03	--	AP-42 Table 1.4-2 [4]
SO_2	0.6	5.77E-04	--	AP-42 Table 1.4-2 [4]

[1] There will be NO_x, CO, VOC, and SO_2 emissions associated with using a gas-fired burner system to bring the unit up to combustion temperature during startup.
The startup burner will combust pipeline quality sweet natural gas
After the system has reached temperature, the burner will be shut off and the system will function using the energy content of the waste stream alone to support combustion.

[2] AP-42 emission factors are converted to heat input rating by dividing by the average heating value (1,020 scf/Btu) and converted to the site-specific heating value by multiplying the emission factor by the ratio of the site-specific to average heating value per AP-42, Table 1-4-1, footnote a.

[3] The burners are rated by the manufacturer to achieve 0.15 lb/MMBtu for both NO_x and CO.

[4] Emission factors are taken from AP-42, Section 1.4, Table 1.4-2 (7/98).

[5] Sulfur content in fuel gas is obtained from a similar Targa facility.

Compound	RTO Emissions [1, 2, 3]	
	(lb/hr)	(tpy)
NO_x	0.45	1.80E-03
CO	0.45	1.80E-03
VOC	0.02	6.34E-05
SO_2	1.73E-03	6.92E-06

[1] Maximum Potential Hourly Emission Rate (lb/hr) = Burner Size (MMBtu/hr) x Emission Factor (lb/MMBtu)

Example NO_x Hourly Emission Rate (lb/hr) =
$$\frac{3\ \text{MMBtu}}{\text{hr}} \times \frac{0.15\ \text{lb}}{\text{MMBtu}} = \frac{0.45\ \text{lb}}{\text{hr}}$$

[2] Maximum Potential Annual Emission Rate (tpy) = Hourly Emission Rate (lb/hr) x Startup Event Duration (hr/event) x Startup Event Frequency (events/yr) x (1 ton / 2,000 lb)

Example NO_x Annual Emission Rate (tpy) =
$$\frac{0.45\ \text{lb}}{\text{hr}} \times \frac{2\ \text{hr}}{\text{event}} \times \frac{4\ \text{events}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1.80\text{E-03 ton}}{\text{yr}}$$

Amine Still Vent (EPN 15)

Amine Still Vent Emissions During Scheduled RTO Downtime [1]

Input Data

Maximum amine acid gas flowrate [2] =	5.76	MMscfd (wet)
Scheduled RTO downtime duration =	38	hr/event
Scheduled RTO downtime frequency =	4	events/yr
Hours of Operation =	152	hrs/yr

Compound	Composition [2] (mol %)	Uncontrolled Amine Emissions [2, 3, 4] (lb/hr)	Uncontrolled Amine Emissions [2, 3, 4] (tpy)
Propane	0.01608316	4.49	0.34
i-Butane	0.00112021	0.41	0.03
n-Butane	0.00454635	1.67	0.13
i-Pentane	0.00027477	0.13	9.53E-03
n-Pentane	0.00047104	0.22	0.02
n-Hexane	0.00008537	0.05	3.54E-03
MDEA	0.00000001	1.13E-05	8.59E-07
Piperazine	0.00000001	2.76E-06	2.10E-07
Benzene	0.01037536	5.13	0.39
Cyclohexane	0.00047987	0.26	0.02
iC7	0.00001886	0.01	9.09E-04
nC7	0.00000502	3.18E-03	2.42E-04
Toluene	0.00859850	5.01	0.38
iC8	0.00000326	2.35E-03	1.79E-04
nC8	0.00000040	2.92E-04	2.22E-05
Ethylbenzene	0.00024043	0.16	0.01
p-Xylene	0.00149297	1.00	0.08
Isononane	0.00000187	1.52E-03	1.16E-04
nC9	0.00000092	7.47E-04	5.68E-05
Decane	0.00000129	1.16E-03	8.81E-05
Hydrogen Sulfide	0.00700000	1.51	0.11
VOC [5]	0.04	18.54	1.41
HAP [6]	0.02	11.35	0.86

[1] During scheduled RTO downtime, the amine acid gas stream will be vented to the atmosphere.

[2] Maximum amine acid gas flowrate, composition data, and uncontrolled hourly emission rates based on amine acid gas stream from ProMax output data.
H_2S content estimated as 70 ppmv or 0.007 mol % maximum.

[3] Hourly H_2S Inlet to RTO (lb/hr) = H_2S MW (lb/lb-mol) x H_2S Composition (mol %) x Waste Gas Flowrate (MMscf/day) x (10^6 scf / 1 MMscf) x (1 day / 24 hr) x (1 lb-mol / 379.5 scf)

$$H_2S \text{ Emissions (lb/hr)} = \frac{34.08 \text{ lb}}{\text{lb-mol}} \times 0.007\ \% \times \frac{5.76 \text{ MMscf}}{\text{day}} \times \frac{10^6 \text{ scf}}{1 \text{ MMscf}} \times \frac{1 \text{ day}}{24 \text{ hr}} \times \frac{1 \text{ lb-mol}}{379.5 \text{ scf}} = \frac{1.51 \text{ lb}}{\text{hr}}$$

[4] Maximum Potential Annual Rate (tpy) = Hourly Rate (lb/hr) x RTO Downtime Duration (hr/event) x RTO Downtime Frequency (events/yr) x (1 ton / 2,000 lb)

$$\text{Example Propane Annual Emission Rate (tpy)} = \frac{4.49 \text{ lb}}{\text{hr}} \times \frac{38 \text{ hr}}{\text{event}} \times \frac{4 \text{ events}}{\text{yr}} \times \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{0.34 \text{ ton}}{\text{yr}}$$

[5] Total VOC taken as the sum of NMNEHC.

[6] Total HAP taken as the sum of all hazardous air pollutants.

TEG Dehydrator Vent (EPN 2)

Dehydrator Vent Emissions During Scheduled RTO Downtime [1]

Input Data

Maximum dehydrator waste gas flowrate [2] =	0.40	MMscfd (wet)
Scheduled RTO downtime duration =	38	hr/event
Scheduled RTO downtime frequency =	4	events/yr
Hours of Operation =	152	hrs/yr

Compound	Composition [2] (mol %)	Uncontrolled Dehydrator Emissions [2, 3, 4] (lb/hr)	(tpy)
Propane	0.45586158	8.83	0.67
i-Butane	0.06606409	1.69	0.13
n-Butane	0.24559984	6.27	0.48
i-Pentane	0.12113445	3.84	0.29
n-Pentane	0.16780609	5.32	0.40
n-Hexane	0.08711980	3.30	0.25
Triethylene Glycol	0.00007432	4.90E-03	3.73E-04
Benzene	0.13569049	4.66	0.35
Cyclohexane	0.07006450	2.59	0.20
iC7	0.10266668	4.52	0.34
nC7	0.03524518	1.55	0.12
Toluene	0.18334286	7.42	0.56
iC8	0.02317373	1.16	0.09
nC8	0.00355417	0.18	0.01
Ethylbenzene	0.00839197	0.39	0.03
p-Xylene	0.03776852	1.76	0.13
Isononane	0.01081312	0.61	0.05
nC9	0.00195458	0.11	8.37E-03
Decane	0.00755507	0.47	0.04
Hydrogen Sulfide	0.00700000	0.10	7.96E-03
VOC [5]	1.76	54.66	4.15
HAP [6]	0.45	17.52	1.33

[1] During scheduled RTO downtime, the dehydrator condenser outlet stream will be vented to the atmosphere.

[2] Maximum dehydrator waste gas flowrate, composition data, and uncontrolled hourly emission rates based on dehydrator condenser outlet stream from ProMax output data. H_2S content estimated as 70 ppmv or 0.007 mol % maximum.

[3] Hourly H_2S Inlet to RTO (lb/hr) = H_2S MW (lb/lb-mol) x H_2S Composition (mol %) x Waste Gas Flowrate (MMscf/day) x (10^6 scf / 1 MMscf) x (1 day / 24 hr) x (1 lb-mol / 379.5 scf)

$$H_2S\text{ Emissions (lb/hr)} = \frac{34.08\text{ lb}}{\text{lb-mol}} \times 0.007\ \% \times \frac{0.40\text{ MMscf}}{\text{day}} \times \frac{10^6\text{ scf}}{1\text{ MMscf}} \times \frac{1\text{ day}}{24\text{ hr}} \times \frac{1\text{ lb-mol}}{379.5\text{ scf}} = \frac{0.10\text{ lb}}{\text{hr}}$$

[4] Maximum Potential Annual Rate (tpy) = Hourly Rate (lb/hr) x RTO Downtime Duration (hr/event) x RTO Downtime Frequency (events/yr) x (1 ton / 2,000 lb)

$$\text{Example Propane Annual Emission Rate (tpy)} = \frac{8.83\text{ lb}}{\text{hr}} \times \frac{38\text{ hr}}{\text{event}} \times \frac{4\text{ events}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.67\text{ ton}}{\text{yr}}$$

[5] Total VOC taken as the sum of NMNEHC.

[6] Total HAP taken as the sum of all hazardous air pollutants.

Flare (EPNs 6, 6-MSS)

Flare Criteria Pollutant Summary [1]

Description	EPN	NO_x		CO		VOC		SO_2		H_2S		HAP	
		Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)	Hourly (lb/hr)	Annual (tpy)
Flare - Pilot Gas	6	0.02	0.09	0.04	0.18	1.39E-04	6.09E-04	7.89E-04	3.46E-03	8.57E-06	3.75E-05	--	--
Flare - MSS	6-MSS	1.79	6.07E-03	3.58	0.01	13.99	0.30	0.03	4.74E-05	3.43E-04	5.14E-07	6.20E-03	8.06E-03
	Total	1.81	0.10	3.62	0.19	13.99	0.30	0.03	3.51E-03	3.51E-04	3.81E-05	6.20E-03	8.06E-03

[1] Total flare emissions based on emission estimates for each inlet stream to the flare.

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - NO_x and CO

Input Data

Gas Stream Heat Value =	1,000	Btu/scf
Number of Pilots =	3	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	150	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.314	MMscf/yr
Gas Stream Heat Input [3] =	0.15	MMBtu/hr
Gas Stream Heat Input [4] =	1,314	MMBtu/yr

Compound	Flare Emission Factors [5] (lb/MMBtu)	Flare Emissions [6, 7]	
		(lb/hr)	(tpy)
NO_x	0.138	0.02	0.09
CO	0.2755	0.04	0.18

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

$$\text{Hourly Flowrate (scf/hr)} = \frac{50.0\text{ scf}}{\text{hr-pilot}} \times 3 = \frac{150\text{ scf}}{\text{hr}}$$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{1.314\text{ MMscf}}{\text{yr}}$$

[3] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Example Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{1{,}000\text{ Btu}}{\text{scf}} \times \frac{1\text{ MMBtu}}{10^6\text{ Btu}} \quad \frac{0.15\text{ MMBtu}}{\text{hr}}$$

[4] Annual Gas Stream Heat Input (MMBtu/yr) = Hourly Gas Stream Heat Input (MMBtu/hr) x Hours of Operation (hrs/yr)

$$\text{Example Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.15\text{ MMBtu}}{\text{hr}} \times \frac{8{,}760\text{ hrs}}{\text{yr}} = \frac{1{,}314\text{ MMBtu}}{\text{yr}}$$

[5] From TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.

[6] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/hr)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{0.138\text{ lb}}{\text{MMBtu}} \times \frac{0.15\text{ MMBtu}}{\text{hr}} = \frac{0.02\text{ lb}}{\text{hr}}$$

[7] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.138\text{ lb}}{\text{MMBtu}} \times \frac{1{,}314\text{ MMBtu}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.09\text{ ton}}{\text{yr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pilot Gas - VOC, SO_2, and H_2S

Input Data

Gas Stream Heat Value =	1,000	Btu/scf
Number of Pilots =	3	
Average Flowrate =	50	scf/hr-pilot
Maximum Flowrate =	0.833	scfm/pilot
Hourly Flowrate [1] =	150	scf/hr
Hours of Operation =	8,760	hrs/yr
Annual Flowrate [2] =	1.314	MMscf/yr

Compound	Composition [3] (Mole %)	MW (lb/lb-mole)	DRE [4] (%)	Gas Vented to Flare [5, 6, 7, 8] (lb/hr)	Gas Vented to Flare (tpy)	Controlled Emissions [8, 9] (lb/hr)	Controlled Emissions (tpy)
Propane	0.04	44	98%	6.96E-03	0.03	1.39E-04	6.09E-04
H_2S		34.08	98%	4.29E-04	1.88E-03	8.57E-06	3.75E-05
VOC [10]	0.04			6.96E-03	0.03	1.39E-04	6.09E-04
SO_2 [11]		64.06				7.89E-04	3.46E-03

[1] Hourly Flowrate (scf/hr) = Average Flowrate (scf/hr-pilot) x Number of Pilots

$$\text{Hourly Flowrate (scf/hr)} = \frac{50.0\text{ scf}}{\text{hr-pilot}} \times 3 = \frac{150\text{ scf}}{\text{hr}}$$

[2] Annual Flowrate (MMscf/yr) = Hourly Flowrate (scf/hr) x Annual Operation (hr/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{8{,}760\text{ hr}}{\text{yr}} \times \frac{1\text{ MMscf}}{10^6\text{ scf}} = \frac{1.314\text{ MMscf}}{\text{yr}}$$

[3] Composition of the gas stream is obtained from Valerus.

[4] Per TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000), 98% of the sulfur content is assumed to be oxidized to SO_2 while the remaining 2% is emitted at H_2S.

[5] Gas Vented to Flare (lb/hr) = Hourly Flowrate (scf/hr) x Mole Percent / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole)

$$\text{Example Propane Hourly Emission Rate (lb/hr)} = \frac{150\text{ scf}}{\text{hr}} \times \frac{0.04\ \%}{100} \times \frac{44\text{ lb}}{\text{lb-mole}} \times \frac{\text{lb-mole}}{379.5\text{ scf}} = \frac{0.01\text{ lb}}{\text{hr}}$$

[6] Sulfur content = 2 grains/100 scf

[7] Hourly H_2S Vented to Flare (lb/hr) = Sulfur Content (grains/100 scf) / 7,000 (grains/lb) x Hourly Flowrate (scf/hr)

$$H_2S\text{ Inlet (lb/hr)} = \frac{2\text{ grains}}{100\text{ scf}} \times \frac{\text{lb}}{7{,}000\text{ grains}} \times \frac{150\text{ scf}}{\text{hr}} = \frac{4.29\text{E-04 lb}}{\text{hr}}$$

[8] Annual Emissions (tpy) = Hourly Emissions (lb/yr) x Hours of Operation (hrs/yr) x (1 ton / 2,000 lb)

$$\text{Example Propane Vented to Flare Annual Emission Rate (tpy)} = \frac{0.01\text{ lb}}{\text{hr}} \times \frac{8{,}760\text{ hrs}}{\text{yr}} \times \frac{1\text{ ton}}{2{,}000\text{ lb}} = \frac{0.03\text{ ton}}{\text{yr}}$$

[9] Controlled Maximum Potential Hourly Emission Rate (lb/hr) = Gas Vented to Flare (lb/hr) x (1 - DRE)

$$\text{Example Controlled Propane Hourly Emission Rate (lb/hr)} = \frac{0.01\text{ lb}}{\text{hr}} \times (1 - 0.98) = \frac{1.39\text{E-04 lb}}{\text{hr}}$$

[10] Total VOC taken as the sum of NMNEHC.

[11] Controlled RTO SO_2 Emission Rate (lb/hr) = [H_2S Inlet (lb/hr) - H_2S Outlet (lb/hr)] x SO_2 MW (lb/lb-mol) / H_2S MW (lb/lb-mol)

$$\text{Controlled } SO_2\text{ Hourly Emission Rate (lb/hr)} = \frac{[4.29\text{E-04} - 8.57\text{E-06}]\text{ lb}}{\text{hr}} \times \frac{64.06\text{ lb/lb-mol}}{34.08\text{ lb/lb-mol}} = \frac{7.89\text{E-04 lb}}{\text{hr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - NO_x and CO [1]

<u>Input Data</u>

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2]=	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input [5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input [6] =	18.00	MMBtu/yr

Compound	Flare Emission Factors [7] (lb/MMBtu)	Flare Emissions [8, 9] (lb/hr)	(tpy)
NO_x	0.138	0.83	1.24E-03
CO	0.2755	1.65	2.48E-03

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shutdown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \; \frac{\text{event}}{1\ \text{hr}} \; 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \; \frac{9\ \text{events}}{\text{yr}} \; \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6{,}000\ \text{scf}}{\text{hr}} \; \frac{1{,}000\ \text{Btu}}{\text{scf}} \; \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \qquad \frac{6.00\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \; \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{18.00\ \text{MMBtu}}{\text{yr}}$$

[7] From TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.

[8] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Hourly Gas Stream Heat Input (MMBtu/hr)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{0.138\ \text{lb}}{\text{MMBtu}} \; \frac{6.00\ \text{MMBtu}}{\text{hr}} = \frac{0.83\ \text{lb}}{\text{hr}}$$

[9] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Annual Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.138\ \text{lb}}{\text{MMBtu}} \; \frac{18.00\ \text{MMBtu}}{\text{yr}} \; \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1.24\text{E-03 ton}}{\text{yr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Residue Compressor Blowdowns - VOC, SO_2, and H_2S

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2] =	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr

Compound	Composition [5] (Mole %)	MW (lb/lb-mole)	DRE [6] (%)	Gas Vented to Flare [7, 8, 9, 10] (lb/hr)	Gas Vented to Flare (tpy)	Controlled Emissions [11, 12] (lb/hr)	Controlled Emissions (tpy)
Propane	0.04	44	98%	0.28	4.17E-04	5.57E-03	8.35E-06
H_2S		34.08	98%	0.02	2.57E-05	3.43E-04	5.14E-07
VOC [13]	0.04			0.28	4.17E-04	5.57E-03	8.35E-06
SO_2		64.06				0.03	4.74E-05

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shutdown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \left| \frac{\text{event}}{1\ \text{hr}} \right| 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \left| \frac{9\ \text{events}}{\text{yr}} \right| \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Composition of the gas stream is obtained from Valerus.

[6] Per TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000), 98% of the sulfur content is assumed to be oxidized to SO_2 while the remaining 2% is emitted at H_2S.

[7] Gas Vented to Flare (lb/hr) = Hourly Flowrate (scf/hr) x Mole Percent (%) / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole)

$$\text{Example Propane Hourly Vented Rate (lb/hr)} = \frac{6{,}000\ \text{scf}}{\text{yr}} \left| \frac{0.04\ \%}{100} \right| \frac{44\ \text{lb}}{\text{lb-mole}} \left| \frac{\text{lb-mole}}{379.5\ \text{scf}} \right| = \frac{2.78\text{E-01 lb}}{\text{hr}}$$

[8] Sulfur content = 2 grains/100 scf

[9] Hourly H_2S Vented to Flare (lb/hr) = Sulfur Content (grains/100 scf) / 7,000 (grains/lb) x Hourly Flowrate (scf/hr)

$$H_2S\ \text{Inlet (lb/hr)} = \frac{2\ \text{grains}}{100\ \text{scf}} \left| \frac{\text{lb}}{7{,}000\ \text{grains}} \right| \frac{6{,}000\ \text{scf}}{\text{hr}} = \frac{0.02\ \text{lb}}{\text{hr}}$$

[10] Gas Vented to Flare (tpy) = Annual Flowrate (MMscf/yr) x Mole Percent (%) / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole) x (10^6 scf/1MMscf) x (1ton/ 2,000 lb)

$$\text{Example Propane Annual Vented Rate (tpy)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \left| \frac{0.04\ \%}{100} \right| \frac{44\ \text{lb}}{\text{lb-mole}} \left| \frac{\text{lb-mole}}{379.5\ \text{scf}} \right| \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \left| \frac{1\ \text{ton}}{2{,}000\ \text{lb}} \right| = \frac{4.17\text{E-04 ton}}{\text{yr}}$$

[11] Controlled Maximum Potential Hourly Emission Rate (lb/hr) = Gas Vented to Flare (lb/hr) x (1 - DRE)
Controlled Maximum Potential Annual Emission Rate (tpy) = Gas Vented to Flare (tpy) x (1 - DRE)

$$\text{Example Controlled Propane Hourly Emission Rate (lb/hr)} = \frac{0.28\ \text{lb}}{\text{hr}} \left| (1 - 0.98) \right| = \frac{5.57\text{E-03 lb}}{\text{hr}}$$

[12] Controlled RTO SO_2 Emission Rate (lb/hr) = [H_2S Inlet (lb/hr) - H_2S Outlet (lb/hr)] x SO_2 MW (lb/lb-mol) / H_2S MW (lb/lb-mol)

$$\text{Controlled } SO_2 \text{ Hourly Emission Rate (lb/hr)} = \frac{[1.71\text{E-02} - 3.43\text{E-04}]\ \text{lb}}{\text{hr}} \left| \frac{64.06\ \text{lb/lb-mol}}{34.08\ \text{lb/lb-mol}} \right| = \frac{0.03\ \text{lb}}{\text{hr}}$$

[13] Total VOC taken as the sum of NMNEHC.

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - NO_x and CO [1]

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2] =	1	hr/event
Event Flowrate =	2,000	scf/event
Annual Event Hours =	9	hrs/yr
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr
Hourly Gas Stream Heat Input [5] =	6.00	MMBtu/hr
Annual Gas Stream Heat Input [6] =	18.00	MMBtu/yr

Compound	Flare Emission Factors [7] (lb/MMBtu)	Flare Emissions [8, 9] (lb/hr)	(tpy)
NO_x	0.138	0.83	1.24E-03
CO	0.2755	1.65	2.48E-03

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shutdown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \times \frac{\text{event}}{1\ \text{hr}} \times 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \times \frac{9\ \text{events}}{\text{yr}} \times \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{6{,}000\ \text{scf}}{\text{hr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{6.00\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{18.00\ \text{MMBtu}}{\text{yr}}$$

[7] From TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.

[8] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Hourly Gas Stream Heat Input (MMBtu/hr)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{0.138\ \text{lb}}{\text{MMBtu}} \times \frac{6.00\ \text{MMBtu}}{\text{hr}} = \frac{0.83\ \text{lb}}{\text{hr}}$$

[9] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Annual Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.138\ \text{lb}}{\text{MMBtu}} \times \frac{18.00\ \text{MMBtu}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1.24\text{E-03 ton}}{\text{yr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Refrigerant Compressor Blowdowns - VOC [1]

Input Data

Number of Compressors =	3	
Annual Number of Events per Compressor =	3	events/compressor-yr
Total Number of Events =	9	events/year
Estimated Event Duration [2]=	1	hr/event
Event Flowrate =	2,000	scf/event
Gas Stream Heat Value =	1,000	Btu/scf
Hourly Flowrate [3] =	6,000	scf/hr
Annual Flowrate [4] =	0.018	MMscf/yr

Compound	Composition (Mole %)	MW (lb/lb-mole)	DRE (%)	Gas Vented to Flare [5] (lb/hr)	Gas Vented to Flare [5] (tpy)	Controlled Emissions [6, 7] (lb/hr)	Controlled Emissions [6, 7] (tpy)
Propane	99.0	44	98%	688.70	1.03	13.77	0.02
VOC [8]	99.0			688.70	1.03	13.77	0.02

[1] Blowdowns from the electric driven compressors are routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] The maximum hourly flowrate occurs during a plant shutdown when all compressors are shutdown at the same time.
Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event) * Number of Compressors

$$\text{Hourly Flowrate (scf/hr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{\text{event}}{1\ \text{hr}} \cdot 3\ \text{compressors} = \frac{6{,}000\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{2{,}000\ \text{scf}}{\text{event}} \cdot \frac{9\ \text{events}}{\text{yr}} \cdot \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.018\ \text{MMscf}}{\text{yr}}$$

[5] Gas Vented to Flare (lb/hr) = Hourly Flowrate (scf/hr) x Mole Percent (%) / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole)

$$\text{Example Propane Hourly Emission Rate (lb/hr)} = \frac{6{,}000\ \text{scf}}{\text{hr}} \cdot \frac{99.00\ \%}{100} \cdot \frac{44\ \text{lb}}{\text{lb-mole}} \cdot \frac{\text{lb-mole}}{379.5\ \text{scf}} = \frac{688.70\ \text{lb}}{\text{hr}}$$

[6] Annual Emissions (tpy) = Annual Flowrate (MMscf/yr) x Mole Percent (%) / 100 x MW (lb/lb-mole) / 379.5 (scf/lb-mole) x (10^6 scf/1MMscf) x (1ton/ 2,000 lb)

$$\text{Example Propane Vented to Flare Annual Emission Rate (tpy)} = \frac{0.018\ \text{MMscf}}{\text{yr}} \cdot \frac{99.00\ \%}{100} \cdot \frac{44\ \text{lb}}{\text{lb-mole}} \cdot \frac{\text{lb-mole}}{379.5\ \text{scf}} \cdot \frac{10^6\ \text{scf}}{1\ \text{MMscf}} \cdot \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = \frac{1.03\ \text{ton}}{\text{yr}}$$

[7] Controlled Maximum Potential Hourly Emission Rate (lb/hr) = Gas Vented to Flare (lb/hr) x (1 - DRE)
Controlled Maximum Potential Annual Emission Rate (tpy) = Gas Vented to Flare (tpy) x (1 - DRE)

$$\text{Example Controlled Propane Hourly Emission Rate (lb/hr)} = \frac{688.70\ \text{lb}}{\text{hr}} \cdot (1 - 0.98) = \frac{13.77\ \text{lb}}{\text{hr}}$$

[8] Total VOC taken as the sum of NMNEHC.

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging MSS - NO_x and CO [1]

Input Data

	Pigging 12"	Pigging 16"	
Annual Number of Events =	52	52	events/year
Estimated Event Duration [2]=	1	1	hr/event
Event Flowrate =	360	640	scf/event
Annual Event Hours =	52	52	hrs/yr
Gas Stream Heat Value =	1,000	1,000	Btu/scf
Hourly Flowrate [3] =	360	640	scf/hr
Annual Flowrate [4] =	0.019	0.033	MMscf/yr
Hourly Gas Stream Heat Input [5] =	0.36	0.64	MMBtu/hr
Annual Gas Stream Heat Input [6] =	18.72	33.28	MMBtu/yr

Compound	Flare Emission Factors [7] (lb/MMBtu)	Flare Emissions [8, 9]			
		Pigging 12" (lb/hr)	Pigging 16" (lb/hr)	Pigging 12" (tpy)	Pigging 16" (tpy)
NO_x	0.138	0.05	0.09	1.29E-03	2.30E-03
CO	0.2755	0.10	0.18	2.58E-03	4.58E-03

[1] Gas vented during pigging operations is routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event)

$$\text{Hourly Flowrate (scf/hr)} = \frac{360 \text{ scf}}{\text{event}} \left| \frac{\text{event}}{1 \text{ hr}} \right. = \frac{360 \text{ scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{360 \text{ scf}}{\text{event}} \left| \frac{52 \text{ events}}{\text{yr}} \right| \frac{1 \text{ MMscf}}{10^6 \text{ scf}} = \frac{0.019 \text{ MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{360 \text{ scf}}{\text{hr}} \left| \frac{1{,}000 \text{ Btu}}{\text{scf}} \right| \frac{1 \text{ MMBtu}}{10^6 \text{ Btu}} \qquad \frac{0.36 \text{ MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.019 \text{ MMscf}}{\text{yr}} \left| \frac{1{,}000 \text{ Btu}}{\text{scf}} \right. = \frac{18.72 \text{ MMBtu}}{\text{yr}}$$

[7] From TCEQ "Air Permit Guidance For Chemical Sources, Flare And Vapor Oxidizers" (Draft Oct. 2000) Table 4, emission factors for industrial flares combusting high-Btu vapors.

[8] Maximum Potential Hourly Emission Rate (lb/hr) = Flare Emission Factor (lb/MMBtu) x Hourly Gas Stream Heat Input (MMBtu/hr)

$$\text{Example } NO_x \text{ Hourly Emission Rate (lb/hr)} = \frac{0.138 \text{ lb}}{\text{MMBtu}} \left| \frac{0.36 \text{ MMBtu}}{\text{hr}} \right. = \frac{0.05 \text{ lb}}{\text{hr}}$$

[9] Maximum Potential Annual Emission Rate (tpy) = Flare Emission Factor (lb/MMBtu) x Annual Gas Stream Heat Input (MMBtu/yr) x (1 ton / 2,000 lb)

$$\text{Example } NO_x \text{ Annual Emission Rate (tpy)} = \frac{0.138 \text{ lb}}{\text{MMBtu}} \left| \frac{18.72 \text{ MMBtu}}{\text{yr}} \right| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{1.29\text{E-03 ton}}{\text{yr}}$$

Flare (EPNs 6, 6-MSS)

Flare Emissions - Pigging MSS - VOC [1]

Input Data

	Pigging 12"	Pigging 16"	
Annual Number of Events =	52	52	events/year
Estimated Event Duration [2]=	1	1	hr/event
Event Flowrate =	360	640	scf/event
Annual Event Hours =	52	52	hrs/yr
Gas Stream Heat Value =	1,000	1,000	Btu/scf
Hourly Flowrate [3] =	360	640	scf/hr
Annual Flowrate [4] =	0.019	0.033	MMscf/yr
Hourly Gas Stream Heat Input [5] =	0.36	0.64	MMBtu/hr
Annual Gas Stream Heat Input [6] =	18.72	33.28	MMBtu/yr

Stream Speciation

Component	MW (lb/lb-mol)	Composition [7] (mol %)	DRE (%)	Hourly Emissions (lb/hr) [8, 9]		Annual Emissions (tpy) [10]	
				Pigging 12"	Pigging 16"	Pigging 12"	Pigging 16"
Propane	44.10	4.508	98%	0.04	0.07	0.05	0.09
i-Butane	58.12	0.491	98%	5.47E-03	9.72E-03	7.11E-03	0.01
n-Butane	58.12	1.219	98%	0.01	0.02	0.02	0.03
i-Pentane	72.15	0.328	98%	4.53E-03	8.06E-03	5.89E-03	0.01
n-Pentane	72.15	0.341	98%	4.71E-03	8.38E-03	6.13E-03	0.01
n-Hexane	86.18	0.117	98%	1.93E-03	3.43E-03	2.51E-03	4.46E-03
Hexane +	86.18	0.180	98%	2.97E-03	5.28E-03	3.86E-03	6.87E-03
Benzene	78.11	0.008	98%	1.20E-04	2.13E-04	1.56E-04	2.77E-04
Cyclohexane	84.16	0.025	98%	4.03E-04	7.16E-04	5.24E-04	9.31E-04
i-Heptane	100.21	0.115	98%	2.21E-03	3.92E-03	2.87E-03	5.10E-03
n-Heptane	100.21	0.031	98%	5.95E-04	1.06E-03	7.74E-04	1.38E-03
Toluene	92.14	0.008	98%	1.41E-04	2.51E-04	1.84E-04	3.26E-04
i-Octane	114.23	0.038	98%	8.31E-04	1.48E-03	1.08E-03	1.92E-03
n-Octane	114.23	0.005	98%	1.09E-04	1.94E-04	1.42E-04	2.53E-04
Ethylbenzene	106.17	--	98%	--	--	--	--
m, o, p Xylene	106.16	0.002	98%	4.07E-05	7.23E-05	5.29E-05	9.40E-05
i-Nonane	128.20	0.009	98%	2.21E-04	3.93E-04	2.87E-04	5.11E-04
n-Nonane	128.20	0.001	98%	2.46E-05	4.37E-05	3.19E-05	5.68E-05
i-Decane	142.29	0.001	98%	2.73E-05	4.85E-05	3.54E-05	6.30E-05
n-Decane	142.29	--	98%	--	--	--	--
i-Undecanes	156.31	0.001	98%	2.99E-05	5.32E-05	3.89E-05	6.92E-05
Total VOC [11]		7.43		0.08	0.14	0.10	0.18
Total HAP		0.14		2.23E-03	3.97E-03	2.90E-03	5.16E-03

Flare (EPNs 6, 6-MSS)

[1] Gas vented during pigging operations is routed to the flare.

[2] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[3] Hourly Flowrate (scf/hr) = Event Flowrate (scf/event) / Event Duration (hrs/event)

$$\text{Hourly Flowrate (scf/hr)} = \frac{360\ \text{scf}}{\text{event}} \times \frac{\text{event}}{1\ \text{hr}} = \frac{360\ \text{scf}}{\text{hr}}$$

[4] Annual Flowrate (MMscf/yr) = Event Flowrate (scf/event) x Total Number of Event (events/yr) x (1 MMscf /10^6 scf)

$$\text{Annual Flowrate (MMscf/yr)} = \frac{360\ \text{scf}}{\text{event}} \times \frac{52\ \text{events}}{\text{yr}} \times \frac{1\ \text{MMscf}}{10^6\ \text{scf}} = \frac{0.019\ \text{MMscf}}{\text{yr}}$$

[5] Hourly Gas Stream Heat Input (MMBtu/hr) = Hourly Flowrate (scf/hr) x Gas Stream Heat Value (Btu/scf) x (1 MMscf /10^6 scf)

$$\text{Hourly Gas Stream Heat Input (MMBtu/hr)} = \frac{360\ \text{scf}}{\text{hr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} \times \frac{1\ \text{MMBtu}}{10^6\ \text{Btu}} \quad \frac{0.36\ \text{MMBtu}}{\text{hr}}$$

[6] Annual Gas Stream Heat Input (MMBtu/yr) = Annual Flowrate (MMscf/yr) x Gas Stream Heat Value (Btu/scf)

$$\text{Annual Gas Stream Heat Input (MMBtu/yr)} = \frac{0.019\ \text{MMscf}}{\text{yr}} \times \frac{1{,}000\ \text{Btu}}{\text{scf}} = \frac{18.72\ \text{MMBtu}}{\text{yr}}$$

[7] Inlet gas composition is calculated from the combination of the New Harp and Waggoner gas streams that will be entering the Longhorn Plant. Provided by Targa to Trinity via email on 12/02/11.

[8] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

[9] Hourly Emission Rate (lb/hr) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) / Event duration (hr/event) x (1 lb-mol / 379.5 scf) x (1- DRE (%))

$$\text{Example Propane Hourly Emission Rate (lb/hr)} = \frac{44.10\ \text{lb}}{\text{lb-mol}} \times \frac{4.508\ \%}{100} \times \frac{360.00\ \text{scf}}{\text{event}} \times \frac{\text{event}}{1\ \text{hr}} \times \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} \times (1 - 98.00\ \%) = \frac{0.04\ \text{lb}}{\text{hr}}$$

[10] Annual Emission Rate (tpy) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) x (1 lb-mol / 379.5 scf) x Number of Events (events/yr) x (1 ton / 2,000 lb)

$$\text{Example Propane Annual Emission Rate (tpy)} = \frac{44.10\ \text{lb}}{\text{lb-mol}} \times \frac{4.508\ \%}{100} \times \frac{360\text{scf}}{\text{event}} \times \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} \times \frac{52\ \text{events}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} \times (1 - 98.00\ \%) = \frac{0.05\ \text{ton}}{\text{yr}}$$

[11] Total VOC taken as the sum of NMNEHC.

Storage Tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18)

Storage Tank Emissions - Negligible Tanks

Storage Tanks with Negligible Emissions [1]

EPN	Description
9	TEG Tank TEG Storage 210 bbl
10	Hot Oil Tank Hot Oil Storage 210 bbl
12	Amine Tank Amine Storage 10 bbl
13	Lube Oil Tank-1 3612 Oil 100 bbl
14	Lube Oil Tank-2 Ref Oil 100 bbl

[1] Emissions are determined negligible based on engineering judgement due to the low vapor pressure and low throughput of each tank.

Storage Tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18)

Storage Tank Physical Characteristics

EPN	Contents	Capacity (bbl)	Capacity (gal)	Tank Orientation	Hourly Throughput (gal/hr)	Annual Throughput (gal/yr)	No. of Turnovers (turnover/yr)	Tank Color	Tank Condition	Height/ Length (ft)	Diameter (ft)
11	Methanol	24	1,000	Horizontal	1,000	52,000	52.00	Gray/White	Good	10.8	4.0
16	Water	210	8,820	Vertical	8,000	416,000	47.17	Gray/White	Good	15.0	10.0
17	LP Cond.	210	8,820	Vertical	8,000	416,000	47.17	Gray/White	Good	15.0	10.0
18	LP Cond.	210	8,820	Vertical	8,000	416,000	47.17	Gray/White	Good	15.0	10.0

VOC Speciation

Component	Condensate [1] wt %	Water [2] wt %
Carbon Dioxide	0.0000	0.0000
Methane	0.0000	0.0000
Ethane	0.0400	0.0400
Propane	0.5900	0.5900
n-Butane	2.0900	2.0900
iso-Butane	0.4900	0.4900
n-Pentane	3.9500	3.9500
iso-Pentane	2.5800	2.5800
Hexanes	10.8466	10.8466
Heptane	24.9901	24.9901
Octanes	30.0836	30.0836
Nonanes	11.6630	11.6630
Decanes +	6.0286	6.0286
Benzene	0.5034	0.5034
Toluene	3.6425	3.6425
Ethylbenzene	0.0931	0.0931
Xylenes	2.4091	2.4091
Total	100.00	100.00
Total VOC	99.96	99.96
Total Hap	6.65	6.65

[1] Condensate speciation is obtained from a condensate analysis performed at a similar Targa site.
[2] Produced water speciation is obtained from a condensate analysis performed at a similar Targa site.

Storage Tanks (EPNs 9, 10, 11, 12, 13, 14, 16, 17, 18)

Storage Tank Emissions - Normal Operations - VOC

Storage Tank Working and Breathing Emissions [1]

EPN	VOC		Benzene		Toluene		Ethylbenzene		Xylenes	
	Hourly Emissions [2, 3] (lb/hr)	Annual Emissions [4] (tpy)	Hourly Emissions [2, 3] (lb/hr)	Annual Emissions [4] (tpy)	Hourly Emissions [2, 3] (lb/hr)	Annual Emissions [4] (tpy)	Hourly Emissions [2, 3] (lb/hr)	Annual Emissions [4] (tpy)	Hourly Emissions [2, 3] (lb/hr)	Annual Emissions [4] (tpy)
11	0.03	0.06	--	--	--	--	--	--	--	--
16	0.40	1.12	1.80E-03	4.88E-03	4.01E-03	0.02	4.03E-05	9.50E-05	7.93E-04	2.02E-03

[1] During normal operations, the methanol tank (EPN-11) and produced water tank (EPN-16) will vent working and breathing losses directly to the atmosphere.
[2] Hourly emissions calculated based on the hourly throughput and the maximum monthly emissions estimated by EPA TANKS 4.09d for the methanol tank.
[3] Hourly emissions calculated based on the hourly throughput and the maximum monthly emissions estimated by EPA TANKS 4.09d for the produced water tank. Produced water is conservatively assumed to have the same composition as LP condensate.
[4] Annual Emissions are based on the average annual throughput and the sum of the monthly emissions estimated by EPA TANKS 4.09d. Annual produced water tank emissions are based on the total losses minus non-VOC components (i.e., ethane).

Storage Tank Emissions - Operations During VRU Downtime - VOC

Storage Tank Breathing Emissions [1]

EPN	VOC		Benzene		Toluene		Ethylbenzene		Xylenes	
	Hourly Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)	Hourly Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)	Hourly Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)	Hourly Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)	Hourly Emissions [2] (lb/hr)	Annual Emissions [3] (tpy)
17	0.11	0.02	5.13E-04	7.39E-05	1.14E-03	1.64E-04	1.04E-05	1.50E-06	1.04E-05	1.50E-06
18	0.11	0.02	5.13E-04	7.39E-05	1.14E-03	1.64E-04	1.04E-05	1.50E-06	1.04E-05	1.50E-06

[1] During VRU downtime, the condensate tanks (EPN-17 and EPN-18) will vent only breathing losses directly to the atmosphere since Targa will not load condensate during VRU downtime. The methanol tank (EPN-11) and produced water tank (EPN-16) will continue to operate normally, with working and breathing losses vented directly to the atmosphere.
[2] Hourly emissions calculated based on the hourly throughput and the maximum monthly emissions estimated by EPA TANKS 4.09d for the condensate tanks.
[3] Annual emissions calculated based on the hourly emissions and 288 hr/yr for VRU downtime.

$$\text{Annual Emission Rate (tpy)} = \frac{0.11\ \text{lb}}{\text{hr}} \times \frac{288\ \text{hr}}{\text{yr}} \times \frac{\text{ton}}{2{,}000\ \text{lb}} = \frac{0.02\ \text{ton}}{\text{yr}}$$

Truck Loading (EPN FUG-2)

Truck Loading Emissions - Normal Operations - VOC

Equation[1]:

$$L_L = \frac{12.46 \times SPM}{T}$$

Variables[1]:

L_L - Loading Loss (lbs/1,000 gal loaded)
S - Saturation Factor (From Table 5.2-1 of AP-42, Section 5.2)
P - True Vapor Pressure of Loaded Liquid (psia)
M - Molecular Weight of Vapor (lb/lb-mol)
T- Temperature of Bulk Liquid (°R = [°F + 460])

Hourly Emissions

EPN	Material Loaded	S [2]	P_{max} [3] (psia)	M_{max} [4] (lb/lb-mol)	T_{max} [5] (°R)	L_L (lb/1,000 gal)	Maximum Hourly Throughput (gal/hr)	Maximum Hourly VOC Emission Rate [6] (lb/hr)
FUG-2	LP Cond.	0.6	4.7163	69.4262	557.80	4.39	8,000	35.11
FUG-2	Water	0.6	4.7163	69.4262	557.80	4.39	8,000	35.11

[1] Loading Loss Equation and Variables are from AP-42, Section 5.2, Transportation and Marketing of Petroleum Liquids (June 2008).
[2] The S-factor is based on submerged loading in dedicated normal service
[3] True vapor pressure is obtained from the EPA TANKS 4.0d output file. The maximum vapor pressure for July is used.
[4] The molecular weight of vapor is obtained from the EPA TANKS 4.0d output file. The maximum vapor molecular weight for July is used.
[5] The maximum July temperature for Dallas, TX is taken from the EPA TANKS 4.09d program as 97.8 °F.
[6] Maximum Hourly Emission Rate (lb/hr) = L_L (lbs/1,000 gal) x Maximum Hourly Throughput (gal/hr)

Maximum Hourly Emission Rate (lb/hr) = $\frac{4.39 \text{ lbs}}{1{,}000 \text{ gal}} \Big| \frac{8{,}000 \text{ gal}}{\text{hr}} = \frac{35.11 \text{ lb}}{\text{hr}}$

Annual Emissions

EPN	Material Loaded	S [2]	P_{avg} [3] (psia)	M_{avg} [4] (lb/lb-mol)	T_{avg} [5] (°R)	L_L (lb/1,000 gal)	Maximum Annual Throughput (gal/yr)	Maximum Annual VOC Emission Rate [6] (tpy)
FUG-2	LP Cond.	0.6	2.8516	69.1058	526.00	2.80	416,000	0.58
FUG-2	Water	0.6	2.8516	69.1058	526.00	2.80	416,000	0.58

[1] Loading Loss Equation and Variables are from AP-42, Section 5.2, Transportation and Marketing of Petroleum Liquids (June 2008).
[2] The S-factor is based on submerged loading in dedicated normal service
[3] True vapor pressure is obtained from the EPA TANKS 4.0d output file. The annual average vapor pressure is used.
[4] The molecular weight of vapor is obtained from the EPA TANKS 4.0d output file. The annual average vapor molecular weight is used.
[5] The annual average temperature for Dallas, TX is taken from the EPA TANKS 4.09d program as 66 °F.
[6] Maximum Annual Emission Rate (tpy) = L_L (lbs/1,000 gal) x Maximum Annual Throughput (gal/yr) / 2,000 (lbs/ton)

Maximum Annual Emission Rate (tpy) = $\frac{2.80 \text{ lbs}}{1{,}000 \text{ gal}} \Big| \frac{416{,}000 \text{ gal}}{\text{yr}} \Big| \frac{1 \text{ ton}}{2{,}000 \text{ lb}} = \frac{0.58 \text{ tons}}{\text{yr}}$

Truck Loading (EPN FUG-2)

Condensate VOC Speciation [1]

Component	wt %	Emission Rate lb/hr [3]	Emission Rate tpy [4]
Propane	0.5900	0.21	3.44E-03
n-Butane	2.0900	0.73	0.01
iso-Butane	0.4900	0.17	2.86E-03
n-Pentane	3.9500	1.39	0.02
iso-Pentane	2.5800	0.91	0.02
Hexanes	10.8466	3.81	0.06
Heptane	24.9901	8.78	0.15
Octanes	30.0836	10.57	0.18
Nonanes	11.6630	4.10	0.07
Decanes +	6.0286	2.12	0.04
Benzene	0.5034	0.18	2.93E-03
Toluene	3.6425	1.28	0.02
Ethylbenzene	0.0931	0.03	5.43E-04
Xylenes	2.4091	0.85	0.01
Total VOC	**99.9600**	**35.11**	**0.58**
Total HAP	**6.648**	**2.33**	**0.04**

Produced Water VOC Speciation [2]

Component	wt %	Emission Rate lb/hr [3]	Emission Rate tpy [4]
Propane	0.5900	0.21	3.44E-03
n-Butane	2.0900	0.73	0.01
iso-Butane	0.4900	0.17	2.86E-03
n-Pentane	3.9500	1.39	0.02
iso-Pentane	2.5800	0.91	0.02
Hexanes	10.8466	3.81	0.06
Heptane	24.9901	8.78	0.15
Octanes	30.0836	10.57	0.18
Nonanes	11.6630	4.10	0.07
Decanes +	6.0286	2.12	0.04
Benzene	0.5034	0.18	2.93E-03
Toluene	3.6425	1.28	0.02
Ethylbenzene	0.0931	0.03	5.43E-04
Xylenes	2.4091	0.85	0.01
Total VOC	**99.9600**	**35.11**	**0.58**
Total HAP	**6.648**	**2.33**	**0.04**

[1] Condensate speciation is obtained from a condensate analysis performed at a similar Targa site.

[2] Produced water speciation is obtained from a condensate analysis performed at a similar Targa site.

[3] Speciated Hourly Emission Rate (lb/hr) = Maximum Hourly Emission Rate (lb/hr) x Component Content (Wt %) / VOC Content (Wt %)

Speciated Propane Hourly Emission Rate (lb/hr) = $\frac{35.11 \text{ lbs}}{\text{hr}} \times \frac{0.5900\ \%}{99.9600\ \%} = \frac{0.21 \text{ lb}}{\text{hr}}$

[4] Speciated Annual Emission Rate (tpy) = Maximum Annual Emission Rate (tpy) x VOC Content (Wt %)

Speciated Propane Annual Emission Rate (tpy) = $\frac{0.58 \text{ ton}}{\text{yr}} \times \frac{0.5900\ \%}{99.9600\ \%} = \frac{3.44\text{E-03 tons}}{\text{yr}}$

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

MSS Activity Emissions Vented to Atmosphere - VOC

MSS Activity [1]	PM Events (events/yr)	Event Duration (hr/event)	Volume per Event (scf/event)	Associated Product Stream [2]
Meters	24	0.017	157	Inlet Gas
Pigging 12"	52	0.017	100	Inlet Gas
Pigging 16"	52	0.017	100	Inlet Gas
Truck Unloading Refrigerant Propane [3]	24	1	0.0055	Liquid Propane

[1] Does not include all MSS activities at the site. Although pigging is sent to the flare, a small portion may be released into the atmosphere during removal of the pig.
[2] Based on process flow diagram provided by Targa, pigging operations occur at the inlet gas stream.
[3] The liquid volume is based on the capacity of the hose nozzle, which has a length of 3 inches and a diameter of 2 inches.

Stream Speciation

Component	MW (lb/lb-mol)	Liquid Density [1] (lb/scf)	Product Stream Mole Percent (%)	
			Inlet Gas [2]	Propane [3]
N_2	28.01		1.035	--
CO_2	44.01		3.952	--
H_2S	34.08		--	--
Methane	16.04		77.776	--
Ethane	30.07		9.811	--
Propane	44.10	31.64	4.508	100.000
i-Butane	58.12		0.491	--
n-Butane	58.12		1.219	--
i-Pentane	72.15		0.328	--
n-Pentane	72.15		0.341	--
n-Hexane	86.18		0.117	--
Hexane +	86.18		0.180	--
Benzene	78.11		0.008	--
Cyclohexane	84.16		0.025	--
i-Heptane	100.21		0.115	--
n-Heptane	100.21		0.031	--
Toluene	92.14		0.008	--
i-Octane	114.23		0.038	--
n-Octane	114.23		0.005	--
Ethylbenzene	106.17		--	--
m, o, p Xylene	106.16		0.002	--
i-Nonane	128.20		0.009	--
n-Nonane	128.20		0.001	--
i-Decane	142.29		0.001	--
n-Decane	142.29		--	--
i-Undecanes	156.31		0.001	--
Total VOC			7.43	100.00
Total HAP			0.14	--

[1] Per Hidnay, A. J. & Parrish, W. R. (2006). "Fundamentals of Natural Gas Processing." Taylor and Francis Group Publishing.
[2] Inlet gas composition is calculated from the combination of the New Harp and Waggoner gas streams that will be entering the Longhorn Plant. Provided by Targa to Trinity via email on 12/02/11.
[3] Refrigerant propane is 100% liquid propane.

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

Speciated Hourly Emissions

Component	Hourly Emissions (lb/hr) [1, 2]				
	Meters [3]	Pigging 12" [3]	Pigging 16" [3]	Truck Unloading Refrigerant Propane	Total
N_2	0.12	0.08	0.08	--	0.28
CO_2	0.73	0.46	0.46	--	1.65
H_2S	--	--	--	--	0.00E+00
Methane	5.21	3.32	3.32	--	11.85
Ethane	1.23	0.78	0.78	--	2.80
Propane	0.83	0.53	0.53	0.17	2.06
i-Butane	0.12	0.08	0.08	--	0.27
n-Butane	0.30	0.19	0.19	--	0.67
i-Pentane	0.10	0.06	0.06	--	0.22
n-Pentane	0.10	0.07	0.07	--	0.23
n-Hexane	0.04	0.03	0.03	--	0.10
Hexane +	0.06	0.04	0.04	--	0.15
Benzene	2.61E-03	1.66E-03	1.66E-03	--	5.93E-03
Cyclohexane	8.79E-03	5.60E-03	5.60E-03	--	0.02
i-Heptane	0.05	0.03	0.03	--	0.11
n-Heptane	0.01	8.26E-03	8.26E-03	--	0.03
Toluene	3.08E-03	1.96E-03	1.96E-03	--	7.00E-03
i-Octane	0.02	0.01	0.01	--	0.04
n-Octane	2.39E-03	1.52E-03	1.52E-03	--	5.42E-03
Ethylbenzene	--	--	--	--	0.00E+00
m, n, p Xylene	8.87E-04	5.65E-04	5.65E-04	--	2.02E-03
i-Nonane	4.82E-03	3.07E-03	3.07E-03	--	0.01
n-Nonane	5.35E-04	3.41E-04	3.41E-04	--	1.22E-03
i-Decane	5.94E-04	3.79E-04	3.79E-04	--	1.35E-03
n-Decane	--	--	--	--	0.00E+00
i-Undecanes	6.53E-04	4.16E-04	4.16E-04	--	1.48E-03
Total VOC	1.66	1.06	1.06	0.17	3.94
Total HAP	0.05	0.03	0.03	--	0.11

[1] Hourly Emission Rate (lb/hr) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) / Event duration (hr/event) x (1 lb-mol / 379.5 scf)

$$\text{Hourly Emission Rate (lb/hr)} = \frac{28.01\ \text{lb}}{\text{lb-mol}} \quad \frac{1.035\ \%}{100} \quad \frac{157.00\ \text{scf}}{\text{event}} \quad \frac{\text{event}}{1\ \text{hr}} \quad \frac{1\ \text{lb-mol}}{379.5\ \text{scf}} = \frac{0.12\ \text{lb}}{\text{hr}}$$

[2] Hourly Emission Rate (lb/hr) = Liquid Volume per Event (scf/event) x Liquid Density (lb/scf) / Event duration (hr/event)

$$\text{Hourly Emission Rate (lb/hr)} = \frac{0.0055\ \text{scf}}{\text{event}} \quad \frac{31.64\ \text{lb}}{\text{scf}} \quad \frac{\text{event}}{1\ \text{hr}} = \frac{0.17\ \text{lb}}{\text{hr}}$$

[3] For events lasting less than 1 hour, it is assumed that no more than 1 event occurs per hour.

Fugitive MSS Activities (EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS)

Speciated Annual Emissions

Component	Annual Emissions (tpy)[1, 2]				
	Meters	Pigging 12"	Pigging 16"	Truck Unloading Refrigerant Propane	Total
N_2	1.45E-03	2.01E-03	2.01E-03	--	5.46E-03
CO_2	8.72E-03	0.01	0.01	--	0.03
H_2S	--	--	--	--	0.00E+00
Methane	0.06	0.09	0.09	--	0.24
Ethane	0.01	0.02	0.02	--	0.06
Propane	9.96E-03	0.01	0.01	2.07E-03	0.04
i-Butane	1.43E-03	1.97E-03	1.97E-03	--	5.38E-03
n-Butane	3.55E-03	4.90E-03	4.90E-03	--	0.01
i-Pentane	1.19E-03	1.64E-03	1.64E-03	--	4.46E-03
n-Pentane	1.23E-03	1.70E-03	1.70E-03	--	4.64E-03
n-Hexane	5.05E-04	6.97E-04	6.97E-04	--	1.90E-03
Hexane +	7.77E-04	1.07E-03	1.07E-03	--	2.92E-03
Benzene	3.13E-05	4.32E-05	4.32E-05	--	1.18E-04
Cyclohexane	1.05E-04	1.46E-04	1.46E-04	--	3.97E-04
i-Heptane	5.78E-04	7.97E-04	7.97E-04	--	2.17E-03
n-Heptane	1.56E-04	2.15E-04	2.15E-04	--	5.85E-04
Toluene	3.69E-05	5.10E-05	5.10E-05	--	1.39E-04
i-Octane	2.18E-04	3.00E-04	3.00E-04	--	8.18E-04
n-Octane	2.86E-05	3.95E-05	3.95E-05	--	1.08E-04
Ethylbenzene	--	--	--	--	0.00E+00
m, n, p Xylene	1.06E-05	1.47E-05	1.47E-05	--	4.00E-05
i-Nonane	5.78E-05	7.98E-05	7.98E-05	--	2.17E-04
n-Nonane	6.43E-06	8.87E-06	8.87E-06	--	2.42E-05
i-Decane	7.13E-06	9.84E-06	9.84E-06	--	2.68E-05
n-Decane	--	--	--	--	0.00E+00
i-Undecanes	7.83E-06	1.08E-05	1.08E-05	--	2.95E-05
Total VOC	0.02	0.03	0.03	2.07E-03	0.08
Total HAP	5.84E-04	8.06E-04	8.06E-04	--	2.20E-03

[1] Annual Emission Rate (tpy) = MW (lb/lb-mol) x Composition (mol %) x MSS Activity Flowrate (scf/event) x (1 lb-mol / 379.5 scf) x Number of Events (events/yr) x (1 ton / 2,000 lb)

$$\text{Annual Emission Rate (tpy)} = \frac{28.01\text{ lb}}{\text{lb-mol}} \left| \frac{1.035\ \%}{100} \right| \frac{157\text{scf}}{\text{event}} \left| \frac{1\text{ lb-mol}}{379.5\text{ scf}} \right| \frac{24\text{ events}}{\text{yr}} \left| \frac{1\text{ ton}}{2{,}000\text{ lb}} \right. = \frac{1.45\text{E-03 ton}}{\text{yr}}$$

[2] Annual Emission Rate for Propane Unloading (tpy) = Liquid Volume per Event (scf/event) x Liquid Density (lb/scf) x Number of Events (events/yr) x (1 ton / 2,000 lb)

$$\text{Annual Emission Rate (tpy)} = \frac{0.0055\text{ scf}}{\text{event}} \left| \frac{31.64\text{ lb}}{\text{scf}} \right| \frac{24\text{ events}}{\text{yr}} \left| \frac{1\text{ ton}}{2{,}000\text{ lb}} \right. = \frac{2.07\text{E-03 ton}}{\text{yr}}$$

Site-wide Fugitive Components (EPN FUG-1)

Fugitive Component Emissions - VOC

Fugitives Counts and VOC Content

Stream	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors	O_2 Sensors	Gas Chromatographs	VOC Content (Weight %)
Inlet Gas	650	2	5,200	12	--	--	1,247	4	1	18.52
Residue Gas	1,242	2	660	5	43	--	3,019	2	1	0.11
Light Oil	211	2	1,688	--	--	--	173	--	--	99.96

LDAR Control [1] (%)

Stream	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors
Gas/Vapor	97	0	30	85	97	97	30
Light Liquid	97	85	30	--	--	97	30

[1] Control efficiency for each type of component for 28 VHP Leak Detection and Repair Program (LDAR).

Oil and Gas Production Operations Emission Factors

	Emission Factor [1] (lb/hr)/component							Emission Factor [2] (scf/hr)	
Stream	Valves	Pumps	Flanges	Compressors	Relief Valves	Open Ended Lines	Connectors	O_2 Sensors	Gas Chromatographs
Gas	0.00992	0.00529	0.00086	0.0194	0.0194	0.00441	0.00044	1.5	1.5
Light Oil	0.0055	0.02866	0.000243	0.0165	0.0165	0.00309	0.000463	--	--

[1] Oil and Gas Production emission factors obtained from TCEQ, Industrial Emissions Assessment Section, Emissions Factors for Equipment Leak Fugitive Components, RG-360, January 2005.

[2] Emission factors for the O_2 sensors and gas chromatographs were provided by Targa.

Site-wide Fugitive Components (EPN FUG-1)

Hourly and Annual VOC Emissions

Stream	Hourly Emissions (lb/hr) [1,2]									
	Valves	**Pumps**	**Flanges**	**Compressors**	**Relief Valves**	**Open Ended Lines**	**Connectors**	**O_2 Sensors**	**Gas Chromatographs**	**Total**
Inlet Gas	0.04	1.96E-03	0.58	6.47E-03	--	--	0.07	0.06	0.02	0.77
Residue Gas	3.98E-04	1.14E-05	4.28E-04	1.57E-05	2.70E-05	--	1.00E-03	1.39E-04	6.97E-05	2.09E-03
Light Oil	0.03	8.59E-03	0.29	--	--	--	0.06	--	--	0.39
									Total	1.16

Stream	Annual Emissions (tpy) [3]									
	Valves	**Pumps**	**Flanges**	**Compressors**	**Relief Valves**	**Open Ended Lines**	**Connectors**	**O_2 Sensors**	**Gas Chromatographs**	**Total**
Inlet Gas	0.16	8.58E-03	2.54	0.03	--	--	0.31	0.27	0.07	3.39
Residue Gas	1.74E-03	4.99E-05	1.88E-03	6.87E-05	1.18E-04	--	4.39E-03	6.11E-04	3.05E-04	9.16E-03
Light Oil	0.15	0.04	1.26	--	--	--	0.25	--	--	1.69
									Total	5.09

[1] Hourly Emissions (lb/hr) = Component Count x Emission Factor [(lb/hr)/ component] x VOC Content (%) / 100 x (1-(28 VHP Control (%)) / 100)

Hourly Emissions (lb/hr) =	650	0.00992 lb	18.52 Wt. %	1-(97/100)	=	0.04 lb/hr
		hr-component	100			

[2] Hourly Emission Rate for O_2 Sensors and Gas Chromatographs (lb/hr) = Sum of the speciated hourly emissions as shown in the VOC Speciation table.

[3] Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x (1 ton / 2,000 lb)

Annual Emissions (tpy) =	0.04 lb	8,760 hrs	1 ton	=	0.16 tpy
	hr	yr	2,000 lb		

Site-wide Fugitive Components (EPN FUG-1)

Stream Speciation

Component	MW (lb/lb-mol)	Stream Mole Percent (%)			Stream Weight Percent (%)		
		Inlet Gas [1]	Residue Gas [2]	Light Oil [3]	Inlet Gas [1]	Residue Gas [2]	Light Oil [3]
N_2	28.01	1.035	1.750	--	1.353	2.996	--
CO_2	44.01	3.952	0.010	0.00E+00	8.118	0.027	0.00E+00
H_2S	34.08	--	--	--	--	--	--
Methane	16.04	77.776	97.500	0.010	58.237	95.583	0.00E+00
Ethane	30.07	9.811	0.700	0.137	13.769	1.286	0.040
Propane	44.10	4.508	0.040	1.300	9.278	0.108	0.590
i-Butane	58.12	0.491	--	0.819	1.332	--	0.490
n-Butane	58.12	1.219	--	3.515	3.307	--	2.090
i-Pentane	72.15	0.328	--	3.499	1.105	--	2.580
n-Pentane	72.15	0.341	--	5.355	1.148	--	3.950
n-Hexane	86.18	0.117	--	--	0.471	--	--
Hexanes	86.18	0.180	--	12.261	0.724	--	10.847
Benzene	78.11	0.008	--	0.633	0.029	--	0.503
Cyclohexane	84.16	0.025	--	--	0.098	--	--
i-Heptane	100.21	0.115	--	--	0.538	--	--
n-Heptane	100.21	0.031	--	25.609	0.145	--	24.990
Toluene	92.14	0.008	--	3.871	0.034	--	3.643
i-Octane	114.23	0.038	--	--	0.203	--	--
n-Octane	114.23	0.005	--	27.425	0.027	--	30.084
Ethylbenzene	106.17	--	--	0.085	--	--	0.093
m, o, p Xylene	106.16	0.002	--	2.217	0.010	--	2.409
i-Nonane	128.20	0.009	--	--	0.054	--	--
n-Nonane	128.20	0.001	--	9.355	0.006	--	11.663
i-Decane	142.29	0.001	--	--	0.007	--	--
n-Decane	142.29	--	--	3.910	--	--	6.029
i-Undecanes	156.31	0.001	--	--	0.007	--	--
Total VOC		7.43	0.04	99.85	18.52	0.11	99.96

[1] Inlet gas composition is calculated from the combination of the New Harp and Waggoner gas streams that will be entering the Longhorn Plant. Provided by Targa to Trinity via email on 12/02/11.

[2] Residue gas composition is obtained from a similar Targa facility.

[3] Light oil composition is obtained from a similar Targa facility.

Site-wide Fugitive Components (EPN FUG-1)

Speciated Hourly Emissions

Component	Hourly Emissions (lb/hr) [1, 2]							
	Inlet Gas			Residue Gas			Light Oil	Total
	Traditional Components	O_2 Sensors	Gas Chromatographs	Traditional Components	O_2 Sensors	Gas Chromatographs		
CO_2	0.30	0.03	6.87E-03	4.70E-04	3.48E-05	1.74E-05	0.00E+00	0.34
Methane	2.19	0.20	0.05	1.67	0.12	0.06	0.00E+00	4.29
Ethane	0.52	0.05	0.01	0.02	1.66E-03	8.32E-04	1.55E-04	0.60
Propane	0.35	0.03	7.86E-03	1.88E-03	1.39E-04	6.97E-05	2.28E-03	0.39
i-Butane	0.05	4.51E-03	1.13E-03	--	--	--	1.89E-03	0.06
n-Butane	0.12	0.01	2.80E-03	--	--	--	8.08E-03	0.15
i-Pentane	0.04	3.74E-03	9.35E-04	--	--	--	9.97E-03	0.06
n-Pentane	0.04	3.89E-03	9.72E-04	--	--	--	0.02	0.06
n-Hexane	0.02	1.59E-03	3.99E-04	--	--	--	--	0.02
Hexane +	0.03	2.45E-03	6.13E-04	--	--	--	0.04	0.07
Benzene	1.09E-03	9.88E-05	2.47E-05	--	--	--	1.95E-03	3.16E-03
Cyclohexane	3.69E-03	3.33E-04	8.32E-05	--	--	--	--	4.10E-03
i-Heptane	0.02	1.82E-03	4.56E-04	--	--	--	--	0.02
n-Heptane	5.44E-03	4.91E-04	1.23E-04	--	--	--	0.10	0.10
Toluene	1.29E-03	1.17E-04	2.91E-05	--	--	--	0.01	0.02
i-Octane	7.60E-03	6.86E-04	1.72E-04	--	--	--	--	8.46E-03
n-Octane	1.00E-03	9.03E-05	2.26E-05	--	--	--	0.12	0.12
Ethylbenzene	--	--	--	--	--	--	3.60E-04	3.60E-04
m, o, p Xylene	3.72E-04	3.36E-05	8.39E-06	--	--	--	9.31E-03	9.73E-03
i-Nonane	2.02E-03	1.82E-04	4.56E-05	--	--	--	--	2.25E-03
n-Nonane	2.25E-04	2.03E-05	5.07E-06	--	--	--	0.05	0.05
i-Decane	2.49E-04	2.25E-05	5.62E-06	--	--	--	--	2.77E-04
n-Decane	--	--	--	--	--	--	0.02	0.02
i-Undecanes	2.74E-04	2.47E-05	6.18E-06	--	--	--	--	3.05E-04
Total VOC	0.70	0.06	0.02	1.88E-03	1.39E-04	6.97E-05	0.39	1.16
Total HAP	0.02	1.84E-03	4.61E-04	--	--	--	0.03	0.05

[1] Speciated Hourly Emissions for Traditional Components (lb/hr) =
Sum of each [Component Count x Emission Factor [(lb/hr)/ component] x Compound Content (wt %) / 100 x (1-28 VHP Control (%) / 100)]

[2] Hourly Emission Rate for O_2 Sensors and Gas Chromatographs (lb/hr) = MW (lb/lb-mol) x Composition (mol %) x Emission Factor (scf/hr) x (1 lb-mol / 379.5 scf) x No. of Components

Propane Speciated Hourly Emission Rate (lb/hr) = $\frac{44.10 \text{ lb}}{\text{lb-mol}} \cdot \frac{4.508 \%}{100} \cdot \frac{1.50 \text{ scf}}{\text{hr}} \cdot \frac{1 \text{ lb-mol}}{379.5 \text{ scf}} \cdot 4 = \frac{0.03 \text{ lb}}{\text{hr}}$

Site-wide Fugitive Components (EPN FUG-1)

Speciated Annual Emissions

Component	Annual Emissions (tpy)[1]							
	Inlet Gas			Residue Gas			Light Oil	Total
	Traditional Components	O_2 Sensors	Gas Chromatographs	Traditional Components	O_2 Sensors	Gas Chromatographs		
CO_2	1.33	0.12	0.03	2.06E-03	1.52E-04	7.62E-05	0.00E+00	1.49
Methane	9.57	0.86	0.22	7.31	0.54	0.27	0.00E+00	18.78
Ethane	2.26	0.20	0.05	0.10	7.29E-03	3.64E-03	6.77E-04	2.63
Propane	1.53	0.14	0.03	8.25E-03	6.11E-04	3.05E-04	9.99E-03	1.72
i-Butane	0.22	0.02	4.94E-03	--	--	--	8.30E-03	0.25
n-Butane	0.54	0.05	0.01	--	--	--	0.04	0.64
i-Pentane	0.18	0.02	4.10E-03	--	--	--	0.04	0.25
n-Pentane	0.19	0.02	4.26E-03	--	--	--	0.07	0.28
n-Hexane	0.08	6.98E-03	1.75E-03	--	--	--	--	0.09
Hexane +	0.12	0.01	2.69E-03	--	--	--	0.18	0.32
Benzene	4.79E-03	4.33E-04	1.08E-04	--	--	--	8.52E-03	0.01
Cyclohexane	0.02	1.46E-03	3.64E-04	--	--	--	--	0.02
i-Heptane	0.09	7.98E-03	2.00E-03	--	--	--	--	0.10
n-Heptane	0.02	2.15E-03	5.38E-04	--	--	--	0.42	0.45
Toluene	5.66E-03	5.10E-04	1.28E-04	--	--	--	0.06	0.07
i-Octane	0.03	3.01E-03	7.51E-04	--	--	--	--	0.04
n-Octane	4.38E-03	3.96E-04	9.89E-05	--	--	--	0.51	0.51
Ethylbenzene	--	--	--	--	--	--	1.58E-03	1.58E-03
m, o, p Xylene	1.63E-03	1.47E-04	3.68E-05	--	--	--	0.04	0.04
i-Nonane	8.85E-03	7.99E-04	2.00E-04	--	--	--	--	9.85E-03
n-Nonane	9.84E-04	8.88E-05	2.22E-05	--	--	--	0.20	0.20
i-Decane	1.09E-03	9.85E-05	2.46E-05	--	--	--	--	1.21E-03
n-Decane	--	--	--	--	--	--	0.10	0.10
i-Undecanes	1.20E-03	1.08E-04	2.71E-05	--	--	--	--	1.33E-03
Total VOC	3.05	0.27	0.07	8.25E-03	6.11E-04	3.05E-04	1.69	5.09
Total HAP	0.09	8.07E-03	2.02E-03	--	--	--	0.11	0.21

[1] Speciated Annual Emissions (tpy) = Hourly Emissions (lb/hr) x 8,760 (hr/yr) x (1 ton / 2,000 lb)

$$\text{Propane Speciated Annual Emissions (tpy)} = \frac{0.35\ \text{lb}}{\text{hr}} \times \frac{8{,}760\ \text{hr}}{\text{yr}} \times \frac{1\ \text{ton}}{2{,}000\ \text{lb}} = 1.53\ \text{tpy}$$

9. EMISSIONS POINT SUMMARY (TCEQ TABLE 1A)

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
1	1	TEG-1 Glycol Reboiler	NO_X	0.22	0.96
			CO	0.12	0.53
			VOC	0.01	0.04
			$PM/PM_{10}/PM_{2.5}$	0.01	0.04
			SO_2	<0.01	<0.01
2	2	TEG Dehydrator During RTO Downtime	VOC	54.66	4.15
			H_2S	0.10	<0.01
			HAPS	17.52	1.33
3	3	HTR-1 Regen Heater	NO_X	1.24	5.43
			CO	0.92	4.03
			VOC	1.74	7.62
			$PM/PM_{10}/PM_{2.5}$	0.09	0.39
			SO_2	0.01	0.04
4	4	HTR-2 Hot Oil Heater	NO_X	4.90	21.46
			CO	7.25	31.76
			VOC	0.52	2.28
			$PM/PM_{10}/PM_{2.5}$	0.72	3.15
			SO_2	0.06	0.25

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**February 2012**	Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Targa Gas Processing LLC - Longhorn Gas Plant**			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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
5	2, 15	RTO-1 Regen Thermal Oxidizer	NO_X	0.11	0.48
			CO	3.32	14.55
			VOC	0.73	3.21
			SO_2	<0.01	13.16
			H_2S	0.02	0.07
			HAPS	0.29	1.26
6	6	Flare-1 Flare (Pilot)	NO_X	0.02	0.09
			CO	0.04	0.18
			VOC	<0.01	<0.01
			SO_2	<0.01	<0.01
			H_2S	<0.01	<0.01
11	11	MEOH-1 Methanol Storage	VOC	0.03	0.06
15	15	Amine Still Vent During RTO Downtime	VOC	18.54	1.41
			H_2S	1.51	0.11
			HAPS	11.35	0.86
16	16	Produced Water Tank 210 bbl	VOC	0.40	1.12
			HAPS	<0.01	0.03
17	17	LP Condensate Tank 1 (During VRU Downtime)	VOC	0.11	0.02
			HAPS	<0.01	<0.01
18	18	LP Condensate Tank 2 (During VRU Downtime)	VOC	0.11	0.02
			HAPS	<0.01	<0.01

TCEQ

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	**February 2012**	Permit No.:	**TBD**	Regulated Entity No.	**TBD**
Area Name:	**Targa Gas Processing LLC - Longhorn Gas Plant**			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	
EPN (A)	FIN (B)	NAME (C)		Pounds per hour (A)	TPY (B)
21	21	Open Drain Sump	VOC	0.01	0.01
FUG-1	FUG-1	Plant-wide Fugitive Components	VOC	1.16	5.09
			HAPS	0.05	0.21
FUG-2	FUG-2	Truck Loading	VOC	70.22	1.17
			HAPS	4.67	0.08
5-MSS	5-MSS	RTO-1 Startup	NO_X	0.45	<0.01
			CO	0.45	<0.01
			VOC	0.02	<0.01
			SO_2	<0.01	<0.01
6-MSS	6-MSS	Flare-1 Flare MSS	NO_X	1.79	<0.01
			CO	3.58	0.01
			VOC	13.99	0.30
			SO_2	0.03	<0.01
			H_2S	<0.01	<0.01
7-MSS	7-MSS	PR-1 16" Reciever	VOC	1.06	0.03
8-MSS	8-MSS	PR-2 12" Reciever	VOC	1.06	0.03
20-MSS	20-MSS	Refrigerant Unloading	VOC	0.17	<0.01
FUG-MSS [1]	FUG-MSS	Plant-wide MSS Fugitives	VOC	1.66	0.02
			HAPS	0.05	<0.01

[1] FUG-MSS does not include pigging or refrigerant loading since those activities have separate EPNs.

TEXAS COMMISSION ON ENVIRONMENTAL QUALITY

Table 1(a) Emission Point Summary

Date:	February 2012	Permit No.:	TBD	Regulated Entity No.	TBD
Area Name:	Targa Gas Processing LLC - Longhorn Gas Plant			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 Height (Feet)	6. Height Above Ground (Feet)	7.Stack Exit Data			8. Fugitives		
EPN (A)	FIN (B)	NAME (C)	Zone	East (Meters)	North (Meters)			Diameter (Feet) (A)	Velocity (fps) (B)	Temperature (°f) (C)	Length (ft.) (A)	Width (ft.) (B)	Axis Degrees (C)
1	1	TEG-1 Glycol Reboiler	14	637,172	3,686,875		16.67	1.33	7.94	750			
2	2	TEG Dehydrator During RTO Downtime	14	637,123	3,686,838		20	0.50	30.15	210.70			
3	3	HTR-1 Regen Heater	14	637,180	3,686,874		18.00	2.50	6.45	680			
4	4	HTR-2 Hot Oil Heater	14	637,190	3,686,867		124.00	6.75	13.89	550			
5	2, 15	RTO-1 Regen Thermal Oxidizer	14	637,194	3,686,857		30.00	3.5	51.97	600			
6	6	Flare-1 Flare (Pilot)	14	637,303	3,686,904		75.00	1.67	TBD	1,000			
11	11	MEOH-1 Methanol Storage	14	637,085	3,686,958		4.00	0.003	0.003	Ambient			
15	15	Amine Still Vent During RTO Downtime	14	637,090	3,686,869		75	1.00	80.30	120			
16	16	Produced Water Tank 210 bbl	14	637,360	3,686,790		15	0.003	0.003	Ambient			
17	17	LP Condensate Tank 1 (During VRU Downtime)	14	637,363	3,686,793		15	0.003	0.003	Ambient			
18	18	LP Condensate Tank 2 (During VRU Downtime)	14	637,366	3,686,797		15	0.003	0.003	Ambient			
21	21	Open Drain Sump	14	637,133	3,686,789		1	0.003	0.003	Ambient			
FUG-1	FUG-1	Plant-wide Fugitive Components	14	637,138	3,686,826		10				1,090	1,043	
FUG-2	FUG-2	Truck Loading	14	637,355	3,686,802		3				50	50	
5-MSS	5-MSS	RTO-1 Startup	14	637,194	3,686,857		30.00	3.50	TBD	TBD			
6-MSS	6-MSS	Flare-1 Flare MSS	14	637,303	3,686,904		75.00	1.67	TBD	1,000			
7-MSS	7-MSS	PR-1 16" Reciever	14	637,007	3,686,726		TBD				TBD	TBD	TBD
8-MSS	8-MSS	PR-2 12" Reciever	14	637,010	3,686,723		TBD				TBD	TBD	TBD
20-MSS	20-MSS	Refrigerant Unloading	14	637,161	3,686,969		TBD				TBD	TBD	TBD
FUG-MSS	FUG-MSS	Plant-wide MSS Fugitives	14	637,138	3,686,826		10				1,090	1,043	

10.1. GENERAL APPLICATION (30 TAC §116.111)

This section provides a summary of the applicable State regulatory requirements outlined in 30 TAC §116.111, *General Application* (effective October 7, 2010).

10.1.1. Form PI-1 General Application (30 TAC §116.111(a)(1))

A completed TCEQ Form PI-1 signed by an authorized representative and all additional support information specified on the form is provided in this permit application.

10.1.2. Protection of Public Health and Welfare (30 TAC §116.111(a)(2)(A))

Targa will comply with all rules and regulations of the commission and with the intent of the Texas Clean Air Act (TCAA; the Act), including protection of the health and property of the public. A review of potentially applicable rules is provided in Section 10.2 through Section 10.11.

As indicated on the area map in Section 5, no elementary, junior high/middle, or senior high schools are located within 3,000 feet of the proposed Longhorn Gas Plant property line.

10.1.3. Measurement of Emissions (30 TAC 116.111(a)(2)(B))

Targa will make necessary provisions for measuring the emissions of significant air contaminants from the Longhorn Gas Plant to demonstrate ongoing compliance with permit limitations, as required by the Executive Director. Targa will follow the guidelines of the "Texas Commission on Environmental Quality Sampling Procedures Manual", as applicable.

10.1.4. Best Available Control Technology (30 TAC 116.111(a)(2)(C))

Section 12 of this permit application demonstrates that the proposed Longhorn Gas Plant will utilize BACT.

10.1.5. New Source Performance Standards (30 TAC 116.111(a)(2)(D))

The following New Source Performance Standards (NSPS) subparts apply to the sources at the proposed facility:

- Subpart A – General Provisions
- Subpart LLL – Onshore Natural Gas Processing: SO_2
- Subpart OOOO - Crude Oil and Natural Gas Production, Transmission, and Distribution

A detailed discussion is located in Section 11 of this application.

10.1.6. National Emissions Standards for Hazardous Air Pollutants (30 TAC 116.111(a)(2)(E))

The Longhorn Gas Plant is not an affected source category under any of the National Emissions Standards for Hazardous Air Pollutants (NESHAP) subparts in Title 40 of the Code of Federal Regulations (40 CFR) Part 61. Therefore the requirements of this part do not apply.

10.1.7. NESHAP for Source Categories (30 TAC 116.111(a)(2)(F))

The following NESHAP subparts in 40 CFR Part 63 applies to this facility:

- Subpart A – General Provisions
- Subpart HH – National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities

Detailed discussion is located in Section 11 of this application.

10.1.8. Performance Demonstration (30 TAC 116.111(a)(2)(G))

The Longhorn Gas Plant will achieve the performance specified in this permit application. Targa will submit additional engineering data or perform ambient monitoring or stack testing for the Longhorn Gas Plant, if required by the TCEQ, to confirm performance as represented in the permit application.

10.1.9. Nonattainment Review (30 TAC 116.111(a)(2)(H))

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[11] In a letter dated December 9, 2011, the U.S. EPA expressed its intent to designate Wise County as nonattainment for the eight-hour ozone standard and include the county in the existing Dallas-Fort Worth ozone nonattainment area.[12]

In the event of a redesignation of Wise County to nonattainment, the proposed Longhorn Gas Plant would be potentially subject to NNSR requirements for NO_x and VOC. Therefore, Targa has provided an analysis in Section 11 of this permit application, demonstrating the proposed Longhorn Gas Plant will not be subject to NNSR permitting requirements.

10.1.10. Prevention of Significant Deterioration Review (30 TAC 116.111(a)(2)(I))

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[13] Therefore, Targa has addressed PSD applicability for NO_X, CO, $PM/PM_{10}/PM_{2.5}$, VOC, and SO_2 in Section 11 of this application.

10.1.11. Air Dispersion Modeling (30 TAC 116.111(a)(2)(J))

Upon request from TCEQ, Targa will submit air dispersion modeling for the proposed Longhorn Gas Plant to confirm performance as represented in the permit application.

10.1.12. Hazardous Air Pollutants (30 TAC 116.111(a)(2)(K))

This regulation refers to 30 TAC Chapter 116, Subchapter E, which applies to new and reconstructed major sources of HAPs that are not subject to a maximum available control technology (MACT) standard under 40 CFR Part 63 when

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[11] Per 40 CFR §81.344 (Effective April 5, 2005).

[12] Letter from Dr. Al Armendariz, U.S. EPA Region 6 Administrator, to Texas Governor Rick Perry, dated December 9, 2011.

[13] Per 40 CFR §81.344 (Effective April 5, 2005).

they are constructed or reconstructed. The Longhorn Gas Plant is not a major source of HAPs; therefore, this rule does not apply.

10.1.13. Mass Cap and Trade Allowances (30 TAC 116.111(a)(2)(L))

This regulation refers to Chapter 101, Subchapter H, Division 3, which applies to facilities in the Houston-Galveston-Brazoria ozone nonattainment area. The Longhorn Gas Plant will not be located in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, the provisions of this regulation do not apply.

10.1.14. Notice Requirements (30 TAC 116.111(b))

Targa will comply with all applicable notice requirements under Chapter 39 and Chapter 55 associated with this permit application.

10.2. GENERAL AIR QUALITY RULES (30 TAC CHAPTER 101)

Targa will comply with all the applicable requirements of the TCEQ General Air Quality Rules as outlined in 30 TAC Chapter 101. The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-1 at the end of this section.

10.3. CONTROL OF AIR POLLUTION FROM VISIBLE EMISSIONS AND PARTICULATE MATTER (30 TAC CHAPTER 111)

30 TAC Chapter 111 outlines applicable requirements for the control of air pollution from visible emissions and particulate matter. The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-2 at the end of this section.

10.4. CONTROL OF AIR POLLUTION FROM SULFUR COMPOUNDS (30 TAC CHAPTER 112)

30 TAC Chapter 112 outlines applicable requirements for the control of air pollution from sulfur compounds. The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-3 at the end of this section.

10.5. STANDARDS OF PERFORMANCE FOR HAPS AND FOR DESIGNATED FACILITIES AND POLLUTANTS (30 TAC CHAPTER 113)

30 TAC Chapter 113 outlines applicable requirements for the control of air pollution from HAPs. The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-4 at the end of this section.

10.6. CONTROL OF AIR POLLUTION FROM MOTOR VEHICLES (30 TAC CHAPTER 114)

The provisions in 30 TAC Chapter 114 regulate emissions from motor vehicles and are not intended for industrial emissions to the atmosphere. Additionally, the Longhorn Gas Plant will not operate any non-road large spark-ignition engines. The permit application does not involve the activities covered by these rules; therefore, the provisions of these rules do not apply to the Longhorn Gas Plant.

10.7. CONTROL OF AIR POLLUTION FROM VOLATILE ORGANIC COMPOUNDS (VOCS) (30 TAC CHAPTER 115)

30 TAC Chapter 115 regulates VOC emissions according to source type and site location (i.e., county). The Longhorn Gas Plant will be located in Wise County, which is considered a covered attainment county for the purposes of Chapter 115 according to 30 TAC §115.10(9). The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-5 at the end of this section.

Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[14] In the event of a re-designation of Wise County to ozone nonattainment, Targa will re-assess the applicability of Chapter 115.

10.8. CONTROL OF AIR POLLUTION BY PERMITS FOR NEW CONSTRUCTION OR MODIFICATION (30 TAC CHAPTER 116)

This permit application for the proposed Longhorn Gas Plant has been submitted to the TCEQ to demonstrate compliance with the applicable provisions of 30 TAC Chapter 116. A Form PI-1 is included in Section 2 of this application and is signed by an authorized Targa representative. All supporting documentation is provided within this application or in the air dispersion modeling report to be submitted under separate cover.

10.9. CONTROL OF AIR POLLUTION FROM NITROGEN COMPOUNDS (30 TAC CHAPTER 117)

30 TAC Chapter 117 regulates NO_X emissions according to source type and site location (i.e., county). The Longhorn Gas Plant will be located in Wise County, which is not a regulated county under Chapter 117. The potential applicability of this chapter to sources at the Longhorn Gas Plant is explained in Table 10.11-6 at the end of this section.

Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[15] In the event of a re-designation of Wise County to ozone nonattainment, Targa will re-assess the applicability of Chapter 117.

10.10. CONTROL OF AIR POLLUTION EPISODES (30 TAC CHAPTER 118)

The Longhorn Gas Plant will comply with the rules relating to generalized and localized air pollution episodes, if such an episode is declared by the TCEQ.

Emission reduction plan requirements apply to major stationary sources in El Paso, Galveston, Harris, Jefferson, and Orange Counties. The Longhorn Gas Plant is located in Wise County, which is not a designated county under §118.5; therefore, no emissions reduction plan is required.

10.11. FEDERAL OPERATING PERMITS (30 TAC CHAPTER 122)

According to the applicability requirements in 30 TAC Chapter 122.120(a)(1), any site that meets the major source definition in §122.10 is subject the requirements of Chapter 122 related to operating permits. 30 TAC Chapter 122.10(13) defines a major source as having the potential to emit (PTE) greater than any of the following limits:

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[14] Per 40 CFR §81.344 (Effective April 5, 2005).

[15] Per 40 CFR §81.344 (Effective April 5, 2005).

- 25 tpy of combined HAPs
- 10 tpy of any single HAP
- 100 tpy of any air pollutant
- 50 tpy of NO_x or VOC in an ozone nonattainment area classified as serious

As further detailed in Section 11, the Longhorn Gas Plant will not be a major source of non-GHG pollutants since the emission thresholds listed above will not be exceeded. Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[16] Even in the event of a re-designation of Wise County to ozone nonattainment, the Longhorn Gas Plant will not be a major source of NO_x or VOC, as shown in Section 11. However, the Longhorn Gas Plant will be a major source of GHG pollutants according to the EPA Tailoring Rule (i.e., the Longhorn Gas Plant will have a PTE of greater than 100,000 tpy of CO_2e).

Note that fugitive emissions are not included in the total PTE for the facility since the sources located at the Longhorn Gas Plant do not fall into any of the source categories listed in §122.10(13)(C).

[16] Per 40 CFR §81.344 (Effective April 5, 2005).

Table 10.11-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.2	Multiple Air Contaminant Sources or Properties	This regulation requires emission reductions from sources and properties that have an additive effect from two or more sources on a single property or from two or more properties when the level of air contaminants exceeds the ambient air quality standards.	No	The Longhorn Plant will be co-located with an electrical substation, which will provide both electrical power to the gas plant and support the local electrical cooperative. However, Targa is not petitioning to designate two or more properties as a single property.
§101.3	Circumvention	This regulation prohibits circumvention of state or federal regulations.	Yes	Targa will not use a plan, activity, device or contrivance to conceal or appear to minimize an emission in violation of the Act or a regulation. The representations made in this permit application ensure no circumvention.
§101.4	Nuisance	This regulation prohibits emission sources from releasing air contaminants in such concentrations and duration as to be injurious to or to adversely affect human health or welfare, animal life, vegetation, or property, or as to interfere with the normal use and enjoyment of animal life, vegetation, or property.	Yes	The representations made in this permit application, the forthcoming ambient air quality modeling and health effects evaluations, and the permit issued based on these representations will ensure compliance with this requirement.
§101.5	Traffic Hazard	This regulation prohibits emissions of air contaminants, uncombined water, or other materials from any source to cause or have a tendency to cause a traffic hazard or interfere with normal road use.	Yes	The representations made in this permit application, the forthcoming ambient air quality modeling and health effects evaluations, and the permit issued based on these representations will ensure compliance with this requirement.
§101.8, §101.9, & §101.14	Sampling; Sampling Ports; and Sampling Procedures and Terminology	These regulations require sampling, access to sampling ports, and that sampling procedures be conducted according the rules specified in this regulation if requested by the TCEQ.	Yes	Targa will conduct requested sampling at the frequency, within the timeframe, and using the methods established by the TCEQ. Targa will provide a sampling port, a power source, and safe access near the point of sampling upon request from TCEQ.
§101.10	Emissions Inventory Requirements	This regulation requires the submittal of annual emissions inventories for facilities meeting certain potential and/or actual emissions levels. This regulation also allows TCEQ to request a special inventory for any source or facility, as deemed necessary by the Commission.	Yes	Targa will submit an annual emissions inventory and all related data as required by this regulation. Targa will submit any special inventory as requested by the TCEQ.

Table 10.11-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.20	Compliance with Environmental Protection Agency Standards	This regulation requires compliance with all applicable NSPS, NESHAP, and PSD requirements as applicable to the facility.	Yes	Targa will comply with any applicable NSPS and NESHAP regulations as demonstrated in Section 11 of this permit application. Targa will comply with any permit issued by the U.S. EPA pursuant to PSD regulations as discussed in Section 11 of this permit application.
§101.21	The National Primary and Secondary Ambient Air Quality Standards	This regulation requires compliance with the National Primary and Secondary Ambient Air Quality Standards as specified in the Federal Clean Air Act.	Yes	Demonstration of compliance with the National Ambient Air Quality Standards will be provided to TCEQ in the forthcoming air quality modeling analysis.
§101.23	Alternate Emission Reduction (“Bubble”) Policy	This regulation allows the owner or operator of a facility to request approval of control of emissions from an alternate facility in lieu of compliance with an applicable regulation (also known as the “bubble” policy).	No	Targa is not requesting a "bubble" under this regulation.
§101.24 & §101.27	Inspection Fees and Emissions Fees	30 TAC §101.24 requires owners and operators to submit inspection fees, as determined by the facility’s Standard Industrial Classification category. 30 TAC §101.27 requires owners and operators with a federal operating permit to submit emissions fees based on allowable levels or actual emissions at the facility.	Yes	If the Longhorn Gas Plant is subject to both inspection and emissions fees, Targa will submit only the greater of the two amounts by the specified due date.
§101.26	Surcharge on Fuel Oil in Specified Boilers	This regulation is applicable to owners and operators of an industrial or utility boiler.	No	Targa is not proposing to operate an industrial or utility boiler at the Longhorn Gas Plant.
§101.28	Stringency Determination for Federal Operating Permits	This regulation allows a federal operating permit holder to comply with more stringent or equivalent requirements.	No	Targa is not requesting a determination under this regulation.
§101.150 - §101.155	Voluntary Supplemental Leak Detection Program	This regulation provides a program that encourages and provides incentives for voluntary monitoring of components.	No	Targa is not seeking participation under this voluntary program since they will be required by TCEQ and/or EPA regulations to monitor equipment components.

Table 10.11-1. 30 TAC Chapter 101 Applicability

Section Number	Reference	Rule Description	Rule Applicability	Compliance Explanation
§101.201 - §101.233	Emissions Events and Scheduled MSS Activities	These regulations provide requirements for the reporting and recordkeeping of emissions events and scheduled maintenance, startup, and shutdown activities.	Yes	Targa will operate all emission sources and control technologies at the Longhorn Gas Plant in a manner in order to reduce the likelihood of an emissions event. If an emissions event were to occur, Targa will comply with all applicable reporting, recordkeeping, and corrective action requirements. Although Targa is including various MSS activities in this application, not all activities may be included. Per Senate Bill (SB) 1134, oil and gas facilities must permit all MSS activities before January 5, 2014.* Targa will permit all MSS activities by this date.
§101.300 - §101.311	Emission Credit Banking and Trading	These regulations outline the guidelines for participating in emission credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system.
§101.350 - §101.363	Mass Emissions Cap and Trade Program	These regulations apply only to sites in the Houston-Galveston-Brazoria ozone nonattainment area.	No	The Longhorn Gas Plant will not be located in the Houston-Galveston-Brazoria ozone nonattainment area. Therefore, these regulations do not apply
§101.370 - §101.379	Discrete Emission Credit Banking and Trading	These regulations outline the guidelines for participating in emissions credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system. .
§101.380 - §101.385	System Cap Trading	These regulations outline the guidelines for participating in emissions credit banking and trading.	No	Targa is not currently proposing to participate in the voluntary emissions credit banking and trading system.
§101.390 - §101.403	Highly-Reactive Volatile Organic Compound Emissions Cap and Trade Program	These regulations apply to sites located in the Houston-Galveston-Brazoria ozone nonattainment area.	No	The Longhorn Gas Plant will not be located in the Houston-Galveston-Brazoria ozone nonattainment area.
§101.501 - §101.508	Clean Air Interstate Rule	These regulations apply to any stationary, fossil fuel-fired boiler or stationary, fossil fuel-fired combustion turbine meeting the Clean Air Interstate Rule (CAIR) applicability requirements under 40 CFR Part 96, Subpart AA or Subpart AAA, relating to NO_x Budget Trading Program and CAIR NO_x and SO_2 Trading Programs for State Implementation Plans.	No	Targa is not currently proposing to install any fossil fuel-fired boiler or turbine at the Longhorn Gas Plant.

* On June 17, 2011, SB 1134 was signed into action by the Governor.

Table 10.11-2. 30 TAC Chapter 111 Applicability

Section Number	Reference	Rule Applicability	Compliance Explanation
§111.111-§111.113	Visible Emissions	Yes	All stationary vents have flowrates less than 100,000 actual cubic feet per minute and will meet the opacity limit of 20% averaged over a six-minute period, as required by §111.111(a)(1)(B). Targa will demonstrate compliance with the opacity limit according to the requirements of §111.111(a)(1)(F)(i)-(iv). As required by §111.111(a)(4), there will be no visible emissions from the flare, except as allowed by §111.111(a)(4)(A). Targa will demonstrate compliance with the visible emission limitation according to the requirements of §111.111(a)(4)(A)(i)-(ii). Alternate opacity limitations are allowed under §111.113. Targa is not requesting an alternate opacity limitation at this time.
§111.121-§111.129	Incineration	No	This initial NSR application does not contain any incineration units.
§111.131-§111.139	Abrasive Blasting of Water Storage Tanks Performed by Portable Operations	No	This initial NSR application does not contain any abrasive blasting of water storage tanks.
§111.141-§111.149	Materials Handling, Construction, Roads, Streets, Alleys, and Parking Lots	No	The Longhorn Gas Plant is not located within any of the geographic areas identified in 30 TAC §111.141.
§111.151	Allowable Emissions Limits	Yes	The only proposed sources of particulate matter are the heaters (EPN 1, 3, and 4), which will not result in emissions in excess of the applicable emission limits specified in 30 TAC §111.151.
§111.153	Emissions Limits for Steam Generators	No	This initial NSR permit application does not contain any oil or gas fuel-fired steam generators with heat input greater than 2,500 MMBtu/hr or any solid fossil fuel-fired steam generators.
§111.171 - §111.175	Emissions Limits on Agricultural Processes	No	This initial NSR permit application does not contain any agricultural processes.
§111.181 - §111.183	Exemptions for Portable or Transient Operations	No	The Longhorn Gas Plant is not proposing to utilize any portable or transient operations engaged in public work projects.
§111.201 - §111.221	Outdoor Burning	No	No outdoor burning will be conducted at the Longhorn Gas Plant.

Table 10.11-3. 30 TAC Chapter 112 Applicability

Section Number	Reference	Rule Applicability	Compliance Explanation
§112.1-§112.21	Control of Sulfur Dioxide	Yes; §112.3	The net ground level concentrations for SO_2 are set forth for the State of Texas in §112.3(a). Targa will provide air dispersion modeling to demonstrate compliance with the net ground level concentration limit of 0.4 part per million by volume (ppmv) averaged over any 30-minute period. The proposed emission sources at the Longhorn Gas Plant are not subject to any other citation within Chapter 112, Subchapter A since there will be no sulfuric acid plants, sulfur recovery plants, solid fossil fuel-fired steam generators, combustion of liquid fuel, or nonferrous smelter processes.
§112.31-§112.34	Control of Hydrogen Sulfide	Yes	The net ground level concentrations for H_2S are set forth for residential, business, commercial, and industrial property in the State of Texas. Demonstration of compliance will be performed per calculation methods set forth in §112.33.
§112.41-§112.47	Control of Sulfuric Acid	No	The Longhorn Gas Plant will not emit sulfuric acid emissions.
§112.51-§112.59	Control of Total Reduced Sulfur	No	The Longhorn Gas Plant will not be a kraft pulp mill.

Table 10.11-4. 30 TAC Chapter 113 Applicability

Subchapter	Reference	Rule Applicability	Compliance Explanation
Subchapter B	National Emission Standard for Hazardous Air Pollutants	No	There are no 40 CFR Part 61 NESHAP requirements applicable to the Longhorn Gas Plant.
Subchapter C	National Emission Standard for Hazardous Air Pollutants for Source Categories	Yes	The TCEQ has incorporated the following MACT subparts in 40 CFR Part 63 that are applicable to the emission sources at the proposed Longhorn Gas Plant: > Subpart A – General Provisions > Subpart HH – National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities Each applicable MACT Subpart of 40 CFR Part 63 is discussed in Section 11 of this application.
Subchapter D	Designated Facilities and Pollutants	No	This initial NSR permit application does not contain a municipal solid waste landfill, a hospital/medical/infectious waste incinerator, municipal waste combustion, or solid waste incineration.
Subchapter E	Consolidated Federal Air Rules: Synthetic Organic Chemical Manufacturing Industry (SOCMI)	No	This initial NSR permit application does not contain any activities subject to SOCMI regulations under 40 CFR Part 65.

Table 10.11-5. 30 TAC Chapter 115 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter B	Division 1	Storage of Volatile Organic Compounds	No	These sections do not apply to Wise County.
	Division 2	Vent Gas Control		
	Division 3	Water Separation		
	Division 4	Industrial Wastewater		
	Division 5	Municipal Solid Waste Landfills		
	Division 6	Batch Processes		
Subchapter C	Division 1	Loading and Unloading of Volatile Organic Compounds	No	These sections apply to covered attainment counties. The Longhorn Gas Plant meets the exemption provided in §115.217(b)(1) for Division 1. All other divisions apply to gasoline transfer operations.
	Division 2	Filling of Gasoline Storage Vessels (Stage 1) for Motor Vehicle Fuel Dispensing Facilities		
	Division 3	Control of Volatile Organic Compound Leaks from Transport Vessels		
	Division 4	Control of Vehicle Refueling emissions (Stage II) at Motor Vehicle Fuel Dispensing Facilities		
	Division 5	Control of Reid Vapor Pressure of Gasoline		
Subchapter D	Division 1	Process Unit Turnaround and Vacuum-Producing Systems in Petroleum Refineries	No	These sections do not apply to Wise County
	Division 2	Fugitive Emission Control in Petroleum Refineries in Greg, Nueces, and Victoria Counties		
	Division 3	Fugitive Emission Control in Petroleum Refining, Natural Gas/Gasoline Processing, and Petrochemical Processes in Ozone Nonattainment Areas		

Table 10.11-5. 30 TAC Chapter 115 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter E	Division 1	Degreasing Operations	No	These sections do not apply to Wise County.
	Division 2	Surface Coating Processes		
	Division 3	Flexographic and Rotogravure Printing		
	Division 4	Offset Lithographic Printing		
	Division 5	Control Requirements for Surface Coating Processes		
	Division 6	Industrial Cleaning Solvents		
	Division 7	Miscellaneous Industrial Adhesives		
Subchapter F	Division 1	Cutback Asphalt	No	These sections do not apply to Wise County.
	Division 2	Pharmaceutical Manufacturing Facilities		
	Division 3	Degassing of Storage Tanks, Transport Vessels, and Marine Vessels		
	Division 4	Petroleum Dry Cleaning Systems		
Subchapter G	Division 1	Automotive Windshield Washer Fluid	No	These sections do not apply to Wise County.
Subchapter H	Division 1	Vent Gas Control	No	These sections do not apply to Wise County.
	Division 2	Cooling Tower Heat Exchange Systems		
	Division 3	Fugitive Emissions		
Subchapter J	Division 1	Alternate Means of Control	No	At this time, the Longhorn Gas Plant is not subject to any Chapter 115 requirements.
	Division 2	Early Reductions		
	Division 3	Compliance and Control Plan Requirements		
	Division 4	Emissions Trading		

Table 10.11-6. 30 TAC Chapter 117 Applicability

Subchapter	Division	Reference	Rule Applicability	Compliance Explanation
Subchapter B	Division 1	Beaumont-Port Arthur Ozone Nonattainment Area Major Sources	No	These sections do not apply to Wise County.
	Division 2	Dallas-Fort Worth Ozone Nonattainment Area Major Sources		
	Division 3	Houston-Galveston-Brazoria Ozone Nonattainment Area Major Sources		
	Division 4	Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Major Sources		
Subchapter C	Division 1	Beaumont-Port Arthur Ozone Nonattainment Area Utility Electric Generation Sources	No	These sections do not apply to Wise County.
	Division 2	Dallas-Fort Worth Ozone Nonattainment Area Utility Electric Generation Sources		
	Division 3	Houston-Galveston-Brazoria Ozone Nonattainment Area Utility Electric Generation Sources		
	Division 4	Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Utility Electric Generation Sources		
Subchapter D	Division 1	Houston-Galveston-Brazoria Ozone Nonattainment Are Minor Sources	No	These sections do not apply to Wise County.
	Division 2	Dallas-Fort Worth Eight-Hour Ozone Nonattainment Area Minor Sources		
Subchapter E	Division 1	Utility Electric Generation in East and Central Texas	No	Divisions 1, 2, and 4 do not apply to Wise County. Division 3 applies only to manufacturers, distributors, retailers, and installers of such units.
	Division 2	Cement Kilns		
	Division 3	Water Heaters, Small Boilers, and Process Heaters		
	Division 4	East Texas Combustion		
Subchapter F	Division 1	Adipic Acid Manufacturing	No	Divisions 1 and 2 do not apply to Wise County. The Longhorn Gas Plant will not be a nitric acid manufacturer.
	Division 2	Nitric Acid Manufacturing – Ozone Nonattainment Areas		
	Division 3	Nitric Acid Manufacturing - General		
Subchapter G	Division 1	Compliance Stack Testing and Reporting Requirements	No	At this time, the Longhorn Gas Plant is not subject to any Chapter 117 requirements.
	Division 2	Emissions Monitoring		
Subchapter H	Division 1	Compliance Schedules	No	At this time, the Longhorn Gas Plant is not subject to any Chapter 117 requirements.
	Division 2	Compliance Flexibility		

This section addresses the applicability of the following parts of 40 CFR for the equipment at the proposed Longhorn Gas Plant:

- NSPS in 40 CFR Part 60
- NESHAP in 40 CFR Part 61
- NESHAP in 40 CFR Part 63, i.e., MACT standards
- Nonattainment New Source Review
- Prevention of Significant Deterioration

11.1. NEW SOURCE PERFORMANCE STANDARDS

The following NSPS subparts in 40 CFR Part 60 are potentially applicable to the emission sources at the proposed Longhorn Gas Plant:

Table 11.1-1. Potentially Applicable NSPS Subparts

Subpart	Description	Applicability	Affected Sources (EPN)
Subpart A	General Provisions	Yes	All sources listed below
Subpart Dc	Standards of Performance for Small Industrial-Commercial-Institutional Steam Generating Units	Yes	Regeneration Heater (EPN 3) Hot Oil Heater (EPN 4)
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	No	N/A
Subpart KKK	Standards of Performance for Equipment Leaks of VOC From Onshore Natural Gas Processing Plants	No	N/A, See NSPS OOOO
Subpart LLL	Standards of Performance for Onshore Natural Gas Processing: SO2 Emissions	No	N/A
Subpart OOOO	Standards of Performance for Crude Oil and Natural Gas Production, Transmission, and Distribution (proposed)	Yes	Fugitives (EPN FUG-1) Tanks (EPN 17 and EPN 18)

Each potentially applicable NSPS subpart of 40 CFR Part 60 is discussed in the subsections below.

11.1.1. Subpart A - General Provisions

Any source subject to a source-specific NSPS is also subject to the general provisions of NSPS Subpart A. Unless specifically excluded by the source-specific NSPS, Subpart A generally requires initial construction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring and/or excess emission reports.

11.1.2. Subpart Dc - Small Industrial-Commercial-Institutional Steam Generating Units

NSPS Subpart Dc applies to steam generating units for which construction, modification, or reconstruction is commenced after June 9, 1989 and that have a maximum design heat input capacity of greater than or equal to 10

MMBtu/hr and less than or equal to 100 MMBtu/hr. According to §60.41c(3), steam generating unit and process heater are defined as:

> *Steam generating unit* means a device that combusts any fuel and produces steam or heats water or heats any heat transfer medium. This term includes any duct burner that combusts fuel and is part of a combined cycle system. This term does not include process heaters as defined in this subpart.
>
> *Process heater* means a device that is primarily used to heat a material to initiate or promote a chemical reaction in which the material participates as a reactant or catalyst.

According to these definitions, the table below lists the emission sources at the proposed Longhorn Gas Plant considered to be steam generating units and are potentially subject to NSPS Subpart Dc.

Table 11.1-2. Heaters Potentially Subject to NSPS Subpart Dc

EPN	Heater Description	Size (MMBtu/hr)
1	TEG Reboiler	2.0
3	Regeneration Heater	12.4
4	Hot Oil Heater	98.0

The TEG Reboiler (EPN 1) is less that 10 MMBtu/hr and therefore, is not subject to the requirements of this rule.

Regeneration Heater (EPN 3) and Hot Oil Heater (EPN 4) are subject to recordkeeping and reporting requirements, since they will not burn coal, oil, or combinations of fuel that included coal and/or oil. Targa will comply with the fuel recordkeeping requirements and the construction and startup notification requirements.

11.1.3. Subpart Kb - Volatile Organic Liquid Storage Vessels

NSPS Subpart Kb applies to volatile organic liquid storage vessels constructed, reconstructed, or modified after July 23, 1984 with a capacity of 19,813 gallons (gal) or more. Targa is proposing to construct multiple storage vessels at the Longhorn Gas Plant; however, since all storage tanks will be smaller than 19,813 gal, this subpart does not apply to this facility.

Table 11.1-3. Storage Tanks Potentially Applicable to NSPS Subpart Kb

EPN	Tank Description	Tank Size (gal)
9	TEG Tank TEG Storage 210 bbl	8,820
10	Hot Oil Tank Hot Oil Storage 210 bbl	8,820
11	MEOH-1 Methanol Storage	1,000
12	Amine Tank Amine Storage 10 bbl	420
13	Lube Oil Tank-1 3612 Oil 100 bbl	4,200
14	Lube Oil Tank-2 Ref Oil 100 bbl	4,200
16	Wastewater Tank 210 bbl	8,820
17	Low Pressure Condensate Tank-1 210 bbl	8,820
18	Low Pressure Condensate Tank-2 210 bbl	8,820

11.1.4. Subpart KKK - Equipment Leaks of VOC From Onshore Natural Gas Processing Plants

NSPS Subpart KKK applies to onshore natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. However, onshore natural gas processing plants constructed, reconstructed, or modified after August 23, 2011 will be subject to the new proposed NSPS Subpart OOOO, as discussed in Section 11.1.6.

11.1.5. Subpart LLL - Onshore Natural Gas Processing: SO_2

NSPS Subpart LLL applies to onshore natural gas processing facilities that contain sweetening units that commence construction or modification after January 20, 1984. However, onshore natural gas processing plants constructed, reconstructed, or modified after August 23, 2011 will be subject to the new proposed NSPS Subpart OOOO, as discussed in Section 11.1.6. It is expected that the following exemptions will be available in the final NSPS Subpart OOOO for onshore natural gas processing facilities that contain sweetening units.

According to §60.641, sweetening unit is defined as:

> *Sweetening unit* means a process device that separates the H_2S and CO_2 contents from the sour natural gas stream.

The Longhorn Gas Plant will contain an amine unit, which separates primarily CO_2 contents from the natural gas stream. Additionally, small amounts of H_2S will be removed in the process. The design capacity of the amine unit will be less than two long tons per day of H_2S in acid gas (expressed as sulfur). Therefore, the amine unit qualifies for exemption from control requirements per §60.640(b). Targa will maintain documentation demonstrating that the facility's design capacity is less than two long tons per day of H_2S expressed as sulfur per §60.647(c).

11.1.6. Subpart OOOO - Crude Oil and Natural Gas Production, Transmission, and Distribution

On July 28, 2011, the EPA Administrator signed a suite of proposed new air regulations affecting both the Production/Processing and Transmission/Storage sectors of the oil and natural gas industry. One of these rules was NSPS Subpart OOOO, expected to regulate emissions of VOC and SO_2 from sources that are newly constructed, modified, or reconstructed after August 23, 2011.

The new NSPS Subpart OOOO may include new or updated emissions and work practice standards for the following source types located at the proposed Longhorn Gas Plant:

- equipment leaks at onshore natural gas processing plants
- condensate storage tanks

Currently, NSPS Subparts KKK and LLL potentially apply to onshore natural gas processing plants constructed, reconstructed, or modified after January 20, 1984. However, any construction, reconstruction, or modification that occurs after August 23, 2011 will be subject to the new requirements of NSPS Subpart OOOO.

As currently proposed, affected facilities subject to NSPS Subpart OOOO must be in compliance with the rule's requirements no later than the date the final rule is published in the Federal Register or the date the facility commences operation, whichever is later. The proposed new rules are expected to be finalized no later than April 3, 2012. At the time of final rule promulgation, Targa will reassess NSPS Subpart OOOO applicability and requirements to the proposed sources at the Longhorn Gas Plant.

11.2. NATIONAL EMISSION STANDARDS FOR HAZARDOUS AIR POLLUTANTS

The Longhorn Gas Plant will not be a major source of HAPs and is therefore not subject to any of the NESHAP subparts in 40 CFR Part 61.

The following MACT subparts in 40 CFR Part 63 are potentially applicable to the emission sources at the proposed Longhorn Gas Plant:

Table 11.2-1. Potentially Applicable MACT Subparts

Subpart	Description	Applicability	Affected Sources (EPN)
Subpart A	General Provisions	Yes	All sources listed below
Subpart HH	National Emission Standards for Hazardous Air Pollutants From Oil and Natural Gas Production Facilities	Yes	TEG Dehydrator (FIN 2/ EPN 5/ EPN 2)
Subpart HHH	National Emission Standards for Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities	No	N/A
Subpart DDDDDD	National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers and Process Heaters	No	N/A
Subpart JJJJJJ	National Emission Standards for Hazardous Air Pollutants For Industrial, Commercial, and Institutional Boilers Area Sources	No	N/A

Each applicable MACT Subpart of 40 CFR Part 63 is discussed in the subsections below.

11.2.1. Subpart A - General Provisions

Any source subject to a source-specific NESHAP is also subject to the general provisions of NESHAP Subpart A. Unless specifically excluded by the source-specific NESHAP, Subpart A generally requires initial construction notification, initial startup notification, performance tests, performance test date initial notification, general monitoring requirements, general recordkeeping requirements, and semiannual monitoring and/or excess emission reports.

11.2.2. Subpart HH - Oil and Natural Gas Production Facilities

MACT Subpart HH applies to emission points at oil and natural gas production facilities that are HAP major or HAP area sources and that process, upgrade, or store either hydrocarbon liquids or natural gas prior to the point of custody transfer. As an area source and facility that processes natural gas, the Longhorn Gas Plant will be potentially subject to the requirements of Subpart HH. According to §63.760(b)(2), the affected sources at HAP area sources include all TEG dehydrator units, as listed below:

Table 11.2-2. TEG Dehydrators Potentially Subject to MACT Subpart HH

FIN	Unit Description
2	TEG Dehydrator *

* The TEG Dehydrator will be controlled by the RTO (EPN 5).

The TEG dehydrator standards of Subpart HH will apply to the dehydrator located at the Longhorn Gas Plant. According to §63.764(e)(1)(ii),the owner/operator is exempt from the general standards if the benzene emissions from the dehydrator are less than 1.0 tpy. As shown in Section 8 of this permit application, the benzene emissions from the dehydrator will be less than 1.0 tpy with federally enforceable controls. Therefore, the unit will only be subject to limited requirements per § 63.774(d)(1)(ii).

11.2.3. Subpart HHH - Hazardous Air Pollutants From Natural Gas Transmission and Storage Facilities

MACT Subpart HHH applies to natural gas transmission and storage facilities that transport or store natural gas prior to entering the pipeline to a local distribution company or to a final end user and are major sources of HAP emissions. Per 40 CFR 63.1270(a), the Longhorn Gas Plant is not an affected source since it is not a major source of HAP emissions and it is not considered a natural gas transmission or storage facility.

11.2.4. Subpart DDDDD - Industrial, Commercial, and Institutional Boilers and Process Heaters

MACT Subpart DDDDD establishes emission limits, operational standards, and compliance demonstration requirements for HAP emissions from industrial, commercial, and institutional boilers and process heaters operating within major sources of HAP emissions. Per 40 CFR §63.7485, the process heaters located at the Longhorn Gas Plant are not subject to this subpart since they will not operate within a major source of HAP emissions.

11.2.5. Subpart JJJJJJ - Industrial, Commercial, and Institutional Boilers Area Sources

MACT Subpart JJJJJJ establishes emission limits, operational standards, and energy assessment requirements for HAP emissions from industrial, commercial, and institutional boilers operating within area sources of HAP emissions. According to 63.11194(a)(1), an affected source is the collection of all existing industrial, commercial, and institutional boilers within a subcategory (coal, biomass, oil). Units at the Longhorn Gas Plant are not subject to Subpart JJJJJJ since they do not fit into one of the subcategories covered by the rule.

11.3. NNSR APPLICABILITY REVIEW

The Longhorn Gas Plant will be located near Decatur in Wise County, Texas. Wise County is currently classified as an attainment/unclassified area for all criteria pollutants.[17] In a letter dated December 9, 2011, the U.S. EPA expressed its intent to designate Wise County as nonattainment for the eight-hour ozone standard and include the county in the existing DFW ozone nonattainment area.[18] In the event of a redesignation of Wise County to nonattainment, the proposed Longhorn Gas Plant may be potentially subject to NNSR requirements for NO_x and VOC.

DFW is currently classified as a serious ozone nonattainment area for the eight-hour ozone standard.[19] It is anticipated that if Wise County is designated as nonattainment for the eight-hour ozone standard, the classification for the county will also be serious. In a serious nonattainment ozone county, NNSR major source thresholds are 50 tpy for NO_x and VOC, each. As shown in the table included at the end of this section, the proposed NO_x and VOC emissions from the Longhorn Gas Plant will be less than 50 tpy, each. Therefore, the proposed Longhorn Gas Plant would not be

[17] Per 40 CFR §81.344 (Effective April 5, 2005).

[18] Letter from Dr. Al Armendariz, U.S. EPA Region 6 Administrator, to Texas Governor Rick Perry, dated December 9, 2011.

[19] Per 40 CFR §81.344 (Effective January 19, 2011).

considered a major source for ozone precursors under the proposed nonattainment designation, and NNSR permitting requirements will not apply to the proposed facility even if Wise County is redesignated a serious ozone nonattainment area under the eight-hour standard.

11.4. PSD APPLICABILITY REVIEW

The proposed Longhorn Gas Plant will be a new major source with respect to GHG emissions and subject to PSD permitting requirements under the GHG Tailoring Rule because emissions of carbon dioxide on an equivalent basis (CO_2e) will be greater than 100,000 tpy.

The proposed facility will be located in Wise County, Texas, which is currently classified as attainment/unclassified for all criteria pollutants.[20] PSD permitting requirements apply to any new major stationary source located in areas designated as attainment/unclassified. Since the proposed Longhorn Gas Plant will be a major source for GHG emissions, EPA requires non-GHG emissions to be compared to the significant emission rates (SER) in accordance with EPA's longstanding "major for one, major for all" PSD policy to determine PSD applicability.[21]

As shown in the table included at the end of this section, emissions for all non-GHG pollutants are less than both major source thresholds and their respective SER. Therefore, the proposed Longhorn Gas Plant will be a minor source with respect to all non-GHG emissions and the facility is subject to the jurisdiction of the TCEQ for such emissions.

Accordingly, Targa is submitting applications to both agencies to obtain the requisite authorizations to construct. The GHG PSD application submitted to EPA is included in Appendix G of this TCEQ NSR permit application for reference.

[20] Per 40 CFR §81.344 (Effective April 5, 2005).

[21] Triggering PSD at Non-Anyway Sources and Modifications, EPA Q&A Document, dated March 15, 2011. http://www.epa.gov/nsr/ghgdocs/TriggeringPSDatnonAnywaySourcesandMods.pdf.

Site-Wide Emission Summary for PSD Applicability

Fugitive emissions are not included in calculculations per 30 TAC § 122.10(13)(C).

Normal Operations Summary

EPN	FIN	Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
1	1	TEG-1 Glycol Reboiler	0.96	0.53	0.04	0.04	0.04	0.04	0.00	1,024.92
2	2	TEG Dehydrator During RTO Downtime	--	--	4.15	--	--	--	--	5.00
3	3	HTR-1 Regen Heater	5.43	4.03	7.62	0.39	0.39	0.39	0.04	6,354.99
4	4	HTR-2 Hot Oil Heater	21.46	31.76	2.28	3.15	3.15	3.15	0.25	50,223.01
5	2, 15	RTO-1 Regen Thermal Oxidizer	0.48	14.55	3.21	--	--	--	13.16	116,291.83
6	6	Flare-1 Flare (Pilot)	0.09	0.18	6.09E-04	--	--	--	3.46E-03	76.87
11	11	MEOH-1 Methanol Storage	--	--	0.06	--	--	--	--	--
15	15	Amine Still Vent During RTO Downtime	--	--	1.41	--	--	--	--	2,027.44
16	16	Produced Water Tank 210 bbl	--	--	1.12	--	--	--	--	--
17	17	LP Condensate Tank 1 (During VRU Downtime)	--	--	0.02	--	--	--	--	--
18	18	LP Condensate Tank 2 (During VRU Downtime)	--	--	0.02	--	--	--	--	--
21	21	Open Drain Sump	--	--	0.01	--	--	--	--	--
		Total Normal Operations Emissions	**28.42**	**51.05**	**19.92**	**3.58**	**3.58**	**3.58**	**13.45**	**176,004.06**

MSS Operations Summary

EPN	FIN	Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
5-MSS	5-MSS	RTO-1 Startup	1.80E-03	1.80E-03	6.34E-05	--	--	--	6.92E-06	1.40
6-MSS	6-MSS	Flare-1 Flare MSS	6.07E-03	1.21E-02	2.95E-01	--	--	--	4.74E-05	8.83
		Total MSS Emissions	**7.87E-03**	**1.39E-02**	**2.95E-01**	**0.00**	**0.00**	**0.00**	**5.43E-05**	**10.23**

Total Operations Summary

		Description	Annual Emissions (tpy)							
			NO_x	CO	VOC	PM	PM_{10}	$PM_{2.5}$	SO_2	CO_2e
		Normal Operations	28.42	51.05	19.92	3.58	3.58	3.58	13.45	176,004.06
		MSS Activities	7.87E-03	1.39E-02	2.95E-01	0.00	0.00	0.00	5.43E-05	10.23
		Total Site-wide Emissions	**28.43**	**51.06**	**20.22**	**3.58**	**3.58**	**3.58**	**13.45**	**176,014.30**

Comparison to PSD Limits [1]

Prevention of Significant Deterioration (PSD) Major Source Threshold	250	250	250	250	250	250	250	100,000
Is the site above PSD major source threshold?	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**NO**	**YES**
Significant Emission Rates (SER)	40	100	40	--	15	10	40	--
Is the site above SERs?	**NO**	**NO**	**NO**	**--**	**NO**	**NO**	**NO**	**--**

[1] According to EPA guidance, the "major for one, major for all" PSD policy applies to GHGs for any project occurring on or after July 1, 2011. Therefore, if a site is a major source of GHGs, then the criteria pollutant emissions must be compared to the Significant Emission Rates to determine PSD applicability.

Comparison to NNSR Limits [1]

Nonattainment New Source Review (NNSR) Limits	50	--	50	--	--	--	--	--
Is the site above NNSR limits?	**NO**	**--**	**NO**	**--**	**--**	**--**	**--**	**--**

[1] Wise County is currently classified as an attainment/unclassified area for all criteria pollutants. In a letter dated December 9, 2011, the U.S. EPA expressed their intent to designate Wise County as nonattainment for the eight-hour ozone standard, including the county in the existing Dallas-Fort Worth serious ozone nonattainment area. In the event of a redesignation of Wise County to nonattainment, the proposed Longhorn Gas Plant would be potentially subject to NNSR requirements for NO_X and VOC.

12. BEST AVAILABLE CONTROL TECHNOLOGY

This section of the permit application evaluates the Best Available Control Technology (BACT) for all the equipment affected by this permit application as set forth in 30 TAC §116.111(a)(2)(C). As previously discussed in Section 11, the potential emissions of all criteria pollutants are below the PSD SER and therefore, do not trigger PSD Review. As such, the criteria pollutant emissions are subject to State BACT review.

30 TAC §116.111(a)(2)(c) provides that the proposed facility will utilize BACT, with consideration given to the technical practicability and economic reasonableness of reducing or eliminating the emissions from the facility. The following sections discuss how each of the proposed sources meets State BACT.

Tier I BACT involves comparison of proposed emission reductions to those approved in recent permit applications for similar processes or industries. As long as no new technical developments have been made that would allow for more stringent controls, based on economic and technical reasonableness, then the previously approved emission reductions may be considered to meet BACT and no further review is necessary. If Tier I BACT is not met, then a Tier II analysis must be performed.

Tier II BACT involves comparison of emission reductions to those approved in recent permit applications for similar air emission streams in different processes or industries. The Tier II BACT may involve a more detailed analysis of technical practicability across different industries/processes, but should not require a detailed economic analysis. If Tier II BACT is not met, then a Tier III analysis must be performed.

Tier III BACT involves a detailed review of all emission reduction options on both a technical and economic basis. Technical feasibility is demonstrated through previous success of an emission reduction strategy, or engineering evaluation of a new technology. Economic feasibility is demonstrated based on the cost effectiveness of controlling emissions (i.e., the dollars per ton of pollutant emissions reduced).

The emission units subject to the State BACT for the Targa Longhorn project include the following:

- Three natural gas-fired heaters: Glycol Reboiler (EPN: 1), Regeneration Heater (EPN: 3), and Hot Oil Heater (EPN: 4)
- One RTO (EPN: 5) controlling emissions from the amine unit (FIN: 15) and the glycol dehydrator (FIN: 2)
- Amine still vent during RTO downtime (EPN: 15)
- Dehydrator condenser outlet during RTO downtime (EPN: 2)
- One flare (EPN: 6)
- Nine storage tanks (EPNs: 9, 10, 11, 12, 13, 14, 16, 17, 18) and an open drain sump (EPN 21)
- Fugitive emissions from piping components (EPN: FUG-1)
- Fugitive emissions from truck loading (EPN: FUG-2)

Emissions also result from the following MSS activities:

- Start-up emissions from the RTO (EPN: 5-MSS) ;
- Plant-wide fugitive MSS fugitives (EPNs: 7-MSS, 8-MSS, 20-MSS, FUG-MSS)
- Flaring of compressor blowdowns and pigging events (EPN: 6-MSS)

The table included at the end of this section provides a summary of TCEQ's Tier I BACT requirements and proposed BACT for normal operations and MSS activities. As demonstrated in the detailed BACT analysis below, all sources meet Tier I BACT.

12.1. PROCESS HEATERS

The three natural-gas fired heaters will be subject to BACT review for NO_x, CO, SO_2, PM_{10}, $PM_{2.5}$, and VOC. The TCEQ provides BACT for NO_x, and CO from combustion sources. For process heaters less than 100 MMBtu/hr, TCEQ's Tier I BACT is a burner with the best NO_x performance given the burner configuration and gaseous fuel used and 50 ppmv corrected to 3% oxygen for CO. If proposed emissions for NO_x are greater than 0.01 lb NO_x/MMBtu, a case-by-case review is needed.[22]

Targa reviewed recently issued permits available at EPA's Reasonably Available Control Technology (RACT)/ BACT/ Lowest Achievable Emission Rate (LAER) Clearinghouse (RBLC Clearinghouse) for miscellaneous boilers, furnaces, and heaters. The RBLC search results are provided in Appendix D of this application, and the emission limits (minimum and maximum) from the RBLC search are included in the table below:

Table 12.1-1. RBLC Summary for NO_X and CO emissions from Process Heaters

Max. Heat Input Rate	NO_X Emission Limit	CO Emission Limit
< 10 MMBtu/hr	0.025 - 0.14 lb/MMBtu Avg.: 0.095 lb/MMBtu	0.03 - 0.0824 lb/MMBtu Avg.:0.048 lb/MMBtu
10 > MMBtu/hr < 100	0.03 - 0.1 lb/MMBtu Avg.: 0.067 lb/MMBtu	0.01 - 0.0824 lb/MMBtu Avg.: 0.045 lb/MMBtu

The maximum heat input rating for the TEG Reboiler (EPN 1) is less than 10 MMBtu/hr and for the Regeneration Heater (EPN 3) and Hot Oil Heater (EPN 4) is less than 100 MMBtu/hr. As show in Table 12.1-2 below, the proposed NO_X and CO emission limits are within the emission limit ranges identified for similar size heaters from the RBLC search.

Targa will utilize good combustion practices and proper heater design to minimize NO_X and CO emissions and proposes the following emission limits as BACT:

Table 12.1-2. Proposed NO_X and CO emission Limits for Process Heaters

Emission Unit	Maximum Heat Input Rate	Proposed NO_X Emission Limit	Proposed CO Emission Limit
TEG Reboiler (EPN 1)	2 MMBtu/hr	0.11 lb/MMBtu	0.06 lb/MMBtu
Regeneration Heater (EPN 3)	12.4 MMBtu/hr	0.1 lb/MMBtu	0.074 lb/MMBtu
Hot Oil Heater (EPN 4)	98 MMBtu/hr	0.050 lb/MMBtu	0.074 lb/MMBtu

[22] TCEQ Combustion Sources, Current Best Available Control Technology Guidelines for Process Furnaces and Heaters dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_processfurn.pdf

The proposed NO_X and CO emission limits for the three heaters are within the emission limit ranges for similar sized units.

There is no TCEQ guidance for BACT for PM_{10}, $PM_{2.5}$, VOC, and SO_2 emissions from the process heaters. Targa proposes the use of natural gas as fuel and good combustion practices as BACT for these emissions.

12.2. AMINE UNIT / TEG DEHYDRATOR / RTO

The Amine Unit, TEG Dehydrator, and RTO will be subject to BACT review for VOC emissions.

There is no TCEQ BACT guidance for amine units. The VOCs removed from the amine vents will be routed to the RTO. A 99% destruction efficiency is based on manufacturer guaranteed destruction. Therefore, Targa proposes the venting of the emissions from the amine unit to the RTO will satisfy BACT requirements. BACT for amine venting during RTO downtime is addressed in Section 12.7 of this application.

TCEQ's Tier I BACT for glycol dehydrators requires that VOC emissions from the glycol dehydrator reboiler still vents be routed to either a flare with a 98% destruction and removal efficiency (DRE) or a firebox with 99+% DRE.[23] Targa proposes to route the dehydrator reboiler still vent to the RTO, which will achieve a 99% DRE. Therefore, the RTO will meet the TCEQ's Tier I BACT requirements for control of the glycol dehydrator emissions. BACT for dehydrator venting during RTO downtime is addressed in Section 12.7 of this application.

TCEQ's Tier I BACT requires RTOs (vapor oxidizers) to achieve a 99% destruction efficiency or a 10 ppmv outlet concentration at 3% oxygen on exhaust VOC.[24] In addition, TCEQ's Tier I BACT requires monitoring of the bed temperature and an initial performance test. The proposed RTO will achieve a 99% destruction efficiency for VOCs and Targa will monitor bed temperature and perform an initial test. Therefore, the RTO will meet the TCEQ's Tier I BACT requirements.

During RTO downtime, the amine treater and TEG dehydrator will be vented directly to the atmosphere. Therefore, this alternate operating scenario is subject to BACT review for VOC. Targa evaluated routing these vent gas streams to the flare when the RTO is down for maintenance. However, this option requires significant supplemental fuel to combust the vent gases, resulting in additional criteria pollutant emissions and expenses due to the cost of the supplemental fuel. Targa estimated the cost of the supplemental fuel to be more than $24,000 per ton of VOC removed based on the heat content of the vent gases. The detailed cost calculations are provided in Appendix E of this application. This cost for supplemental fuel is not considered economically reasonable. Therefore, BACT does not require routing the vent gases to the flare during RTO maintenance is not feasible. Targa will minimize the RTO downtime with proper maintenance of the RTO and will minimize the duration of maintenance activities. This, in turn, will reduce the uncontrolled emissions from the amine treater and dehydrator vented directly to the atmosphere. Targa expects that quarterly maintenance may be required to ensure proper operation of the RTO and each maintenance event may last 38 hours (i.e., 152 hours per year). Therefore, Targa proposes minimizing maintenance downtime of the RTO as meeting BACT.

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[23] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Glycol Dehydrator dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_glycoldehyd.pdf

[24] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Vapor Oxidizers dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_vaporox.pdf

12.3. FLARE

The flare (EPN 6 and 6-MSS) will be used to destroy the off-gas produced during emergency situations and during planned MSS activities. Pipeline quality natural gas will be used as pilot gas. The flare will be subject to TCEQ BACT for VOC. TCEQ's BACT for flares includes the minimum requirement of meeting 40 CFR §60.18 (General control device and work practice requirements) with the following control efficiency requirements:[25]

- Destruction efficiency of 99% for compounds up to three carbons;
- Destruction efficiency of 98% for all others; and
- No flaring of halogenated compounds allowed.

The proposed flare will meet 40 CFR §60.18 performance specifications. In addition, the flare will achieve a destruction efficiency of 99% for compounds up to three carbons and 98% otherwise. Flaring of halogenated compounds will not be performed. The net heating value of gas combusted in the air-assisted flare will be greater than 300 Btu/scf. This will promote flame stability and sufficient destruction efficiency. This satisfies TCEQ's Tier I BACT for VOC.

12.4. ATMOSPHERIC STORAGE TANKS

The proposed Longhorn Gas Plant includes the following tanks:

Table 12.4-1. Atmospheric Storage Tanks Located at Longhorn Gas Plant

EPN	Tank Description	Tank Size (gal)
9	TEG Tank TEG Storage 210 bbl	8,820
10	Hot Oil Tank Hot Oil Storage 210 bbl	8,820
11	MEOH-1 Methanol Storage	1,000
12	Amine Tank Amine Storage 10 bbl	420
13	Lube Oil Tank-1 3612 Oil 100 bbl	4,200
14	Lube Oil Tank-2 Ref Oil 100 bbl	4,200
16	Wastewater Tank 210 bbl	8,820
17	Low Pressure Condensate Tank-1 210 bbl	8,820
18	Low Pressure Condensate Tank-2 210 bbl	8,820

Tanks 9, 10, 12, 13, and 14 have both a low vapor pressure and low throughput. These tanks will be constructed with fixed roofs and painted grey or white. Targa proposes the construction of these negligible tanks to be BACT.

For storage tanks with capacity less than 25,000 gallons or vapor pressure less than 0.5 psia, TCEQ's Tier I BACT requires a fixed roof with submerged fill and white or aluminum un-insulated exterior surfaces exposed to the sun.[26] The produced water tank (16) and condensate tanks (17 and 18) will be less than 25,000 gallons in capacity. In addition, these tanks will be fixed roof tanks with submerged fill and painted grey or white. Therefore, the storage tanks meet TCEQ Tier I BACT requirements.

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[25] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Flares and Vapor Combustors dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_flares.pdf

[26] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Storage Tanks dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_tanks.pdf

Furthermore, the flash losses, working losses, and breathing losses from the condensate tanks (17 and 18) will be controlled by a VRU with 100% capture efficiency, which exceeds the minimum BACT requirements.

12.5. FUGITIVE EMISSIONS FROM PIPING COMPONENTS

The fugitive emissions from the piping components will be subject to TCEQ BACT for VOC emissions. TCEQ Tier I BACT for fugitives is included in the Table 12.5-1 below.[27]

Table 12.5-1. TCEQ BACT Summary for Fugitive Emissions

Pollutant	Minimum Acceptable Control	Control Efficiency Details
Uncontrolled VOC emissions < 10 tpy	None	
10 tpy < uncontrolled VOC emissions < 25 tpy	28M leak detection and repair program (LDAR)	75% credit for 28M
Uncontrolled VOC emissions > 25 tpy	28 VHP LDAR	97% credit for valves, 85% for pumps and compressors
VOC vp < 0.002 psia	No inspection required	No fugitive emissions expected
Approved odorous compounds: NH_3, $C1_2$, H_2S, etc.	Audio/Visual/Olfactory (AVO) inspection twice per shift	Appropriate credit for AVO program

The potential uncontrolled VOC annual fugitive emissions will be greater than 10 tpy but less than 25 tpy for the Longhorn Gas Plant and therefore, at least a 28M LDAR program is required. Targa will implement a 28 VHP LDAR program at the Longhorn Gas Plant, exceeding the BACT requirements for VOC.

12.6. FUGITIVE EMISSIONS FROM TRUCK LOADING OPERATIONS

The fugitive emissions from truck loading operations are subject to BACT review for VOC. Produced water and low pressure condensate (LP condensate) will be shipped off-site via trucks. For loading operations that contain VOCs with vapor pressure less than 0.5 psia, TCEQ Tier I BACT requires submerged or bottom loading as the minimum acceptable control and no splash loading.[28] For loading operations that contain VOCs with vapor pressure greater than 0.5 psia, TCEQ Tier I BACT requires that the emissions are routed to a VOC control device.[29]

The vapor pressure for the produced water and LP condensate will be greater than 0.5 psia. The proposed truck loading operations at the proposed Longhorn Gas Plant will be submerged loading with dedicated normal service for both produced water and LP condensate. Total loading emissions are expected to be 1.17 tpy of VOC. Given the low annual emission rate, Targa proposes submerged loading with dedicated normal service is considered BACT for this emission source.

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[27] TCEQ Chemical Sources Current Best Available Control Technology Requirements for Equipment Leak Fugitives dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_fugitives.pdf

[28] TCEQ Chemical Sources Current Best Available Control Technology Requirements for loading operations dated 8/1/2011, http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_loading.pdf

[29] Ibid.

12.7. MSS EMISSIONS FROM RTO

MSS emissions associated with the RTO startup are subject to BACT review for NO_x, CO, SO_2, and VOC. The RTO will utilize a 3-MMBtu/hr gas-fired burner system to bring the RTO up to combustion temperature during startup. After the system has reached temperature, the burners will be shut off and the system will function using the energy content of the amine and dehydrator waste streams alone to support combustion. Emissions from the startup burner system will result from the combustion of pipeline quality natural gas. No waste gas will be combusted in the startup burner. The startup burner is guaranteed to meet a NOx emission rate of 0.15 lb/MMBtu and a CO emission rate of 0.15 MMBtu/hr. The startup burner is expected to operate no more than 8 hours per year. Additionally, annual emissions of each pollutant are expected to be less than 0.01 tpy each. Therefore, Targa is proposing good combustion practices, combusting only pipeline quality natural gas, and minimizing startup time as BACT for operation of the RTO startup burner. No emissions are expected from the RTO during shutdown or maintenance activities.

12.8. PLANT-WIDE MSS FUGITIVE EMISSIONS

Plant-wide MSS fugitive emissions are subject to BACT review for VOC. Fugitive emissions result from maintenance activities for meters, pigging, and refrigerant propane unloading from trucks. The potential emissions are estimated as 0.08 tpy. Given the low annual emission rate for MSS activities, Targa proposes to minimize the duration and frequency of these MSS activities in order to reduce potential emissions to satisfy BACT requirements.

Summary of TCEQ BACT Requirements and Proposed BACT

Emission Source	Pollutant	TCEQ Tier I BACT	Case-by-Case Review Required?	Case-by-Case Considerations	Proposed BACT
Process Heaters [1] EPNs 1, 3, 4	NO_x	Burners with the best NO_x performance given the burner configuration and gaseous fuel used. Case-by-case review necessary if NO_x > 0.01 lb/MMBtu.	Yes	RBLC search results for process heaters < 10 MMBtu/hr: 0.025 - 0.14 lb/MMBtu Avg.: 0.095 lb/MMBtu RBLC search results for process heaters > 10 MMBtu/hr, < 100 MMBtu/hr: 0.03 - 0.1 lb/MMBtu Avg.: 0.067 lb/MMBtu	EPN 1: 0.11 lb/MMBtu EPN 3: 0.1 lb/MMBtu EPN 4: 0.050 lb/MMBtu Use of natural gas as fuel and good combustion practices.
	CO	50 ppmv corrected to 3% O_2	Yes	RBLC search results for process heaters < 10 MMBtu/hr: 0.03 - 0.0824 lb/MMBtu Avg.: 0.048 lb/MMBtu RBLC search results for process heaters > 10 MMBtu/hr, < 100 MMBtu/hr: 0.01 - 0.0824 lb/MMBtu Avg.: 0.045 lb/MMBtu	EPN 1: 0.06 lb/MMBtu EPN 3: 0.074 lb/MMBtu EPN 4: 0.074 lb/MMBtu Use of natural gas as fuel and good combustion practices.
	PM10, PM2.5, VOC, and SO_2	N/A	Yes	N/A	Use of natural gas as fuel and good combustion practices
Amine Treater FIN 15, EPN 5	VOC	N/A	Yes	N/A	Route the amine treater still vent to RTO, with 99% destruction efficiency for VOCs.
Glycol Dehydrator [2] FIN 2, EPN 5	VOC	Route reboiler stills vent to control (flare or firebox), with 98% DRE for flare or with 99+% DRE for firebox.	No	N/A	Route the dehydrator reboiler still vent to RTO, with 99% destruction efficiency for VOCs.
Regenerative Thermal Oxidizer [3] EPN 5	VOC	Monitor bed temperature, perform initial test. 99% destruction or 10 ppmv outlet concentration.	No	N/A	Achieve 99% destruction efficiency, monitor bed temperature, and perform initial test.
Flare [4] EPNs 6, 6-MSS	VOC	Flare required to meet 40 CFR 60.18. Destruction Efficiency: 99% for certain compounds up to three carbons, 98% otherwise. No flaring of halogenated compounds allowed.	No	N/A	Flare will meet 40 CFR 60.18 requirements. In addition, the flare will achieve a destruction efficiency of 99% for compounds up to three carbons and 98% otherwise. Halogenated compounds will not be flared.
Storage Tanks [5] EPNs 16, 17, 18	VOC	Tank capacity < 25 Mgal or Vp < 0.5 psia: Fixed roof with submerged fill. White or aluminum uninsulated exterior surfaces exposed to the sun.	No	N/A	Produced water and condensate will be fixed roof tanks with submerged fill and painted grey/white.
Fugitive Components [6] EPN FUG-1	VOC	10 tpy < uncontrolled VOC emissions < 25 tpy: 28M LDAR	No	N/A	28 VHP LDAR program
Loading Operations [7] EPN FUG-2	VOC	VOC vp > 0.5 psia: - Route to VOC control device - Annual truck leak checking	Yes	Total loading emissions are expected to be 1.17 tpy of VOC.	Submerged loading with dedicated normal service.

Summary of TCEQ BACT Requirements and Proposed BACT

Emission Source	Pollutant	TCEQ Tier I BACT	Case-by-Case Review Required?	Case-by-Case Considerations	Proposed BACT
Regenerative Thermal Oxidizer Startup [1] EPN 5-MSS	NO_x	Burners with the best NO_x performance given the burner configuration and gaseous fuel used. Case-by-case review necessary if NO_x > 0.01 lb/MMBtu.	Yes	The startup burner is expected to operate no more than 8 hours per year. NO_x emissions < 0.01 tpy.	0.15 lb/MMBtu Use of natural gas as fuel, good combustion practices, and minimizing startup time.
	CO	50 ppmv corrected to 3% O_2	Yes	The startup burner is expected to operate no more than 8 hours per year. CO emissions < 0.01 tpy.	0.15 lb/MMBtu Use of natural gas as fuel, good combustion practices, and minimizing startup time.
	VOC, SO_2	N/A	Yes	The startup burner is expected to operate no more than 8 hours per year. VOC emissions < 0.01 tpy. SO_2 emissions < 0.01 tpy.	Use of natural gas as fuel, good combustion practices, and minimizing startup time.
Amine Treater during RTO Downtime EPN 15	VOC	N/A	Yes	The cost of the supplemental fuel to route waste gas to the flare would be more than $24,000 per ton of VOC removed based on the heat content of the amine and dehydrator vent gases. This is economically infeasible.	Vent amine treater emissions directly to the atmosphere during RTO downtime. Minimize the RTO downtime with proper maintenance of the RTO.
Glycol Dehydrator during RTO downtime [2] EPN 2	VOC	Route reboiler stills vent to control (flare or firebox), with 98% DRE for flare or with 99+% DRE for firebox.	Yes	The cost of the supplemental fuel to route waste gas to the flare would be more than $24,000 per ton of VOC removed based on the heat content of the amine and dehydrator vent gases. This is economically infeasible.	Vent dehydrator emissions directly to the atmosphere during RTO downtime. Minimize the RTO downtime with proper maintenance of the RTO.
Fugitive MSS Activities EPNs 7-MSS, 8-MSS, 20-MSS, FUG-MSS	VOC	N/A	Yes	VOC emissions from all permitted MSS activities are estimated to be 0.30 tpy of VOC.	Minimize the duration and frequency of fugitive MSS activities.

[1] TCEQ Combustion Sources, Current Best Available Control Technology Guidelines for Process Furnaces and Heaters dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_processfurn.pdf

[2] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Glycol Dehydrator dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_glycoldehyd.pdf

[3] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Vapor Oxidizers dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_vaporox.pdf

[4] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Flares and Vapor Combustors dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_flares.pdf

[5] TCEQ Chemical Sources, Current Best Available Control Technology Requirements for Storage Tanks dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_tanks.pdf

[6] TCEQ Chemical Sources Current Best Available Control Technology Requirements for Equipment Leak Fugitives dated 8/1/2011.
Air Permit Technical Guidance for Chemical Sources: Equipment Leak Fugitives, October 2000.

[7] TCEQ Chemical Sources Current Best Available Control Technology Requirements for loading operations dated 8/1/2011.
http://www.tceq.texas.gov/assets/public/permitting/air/Guidance/NewSourceReview/bact/bact_loading.pdf

13. COMPLIANCE ASSURANCE MONITORING REQUIREMENTS

Per 30 TAC §122.604(b), CAM is required for sources that meet all of the following requirements:

- The emission unit is subject to an emission limitation or standard for an air pollutant (or surrogate thereof) in an applicable requirement
- The emission unit uses a control device to achieve compliance with the emission limitation or standard
- The emission unit has pre-control device potential to emit (PTE) greater than or equal to the amount in tons per year required for a site to be classified as a major source

Exemptions to CAM requirements are listed in 30 TAC §122.604(c) and include the following:

- Emission limitations or standards in NSPS or NESHAP subparts proposed by the U.S. EPA after November 15, 1990
- Emission limitations or standards for which an applicable requirement specifies a continuous compliance determination method, unless the applicable compliance method includes an assumed control device emission reduction factor that could be affected by the actual operation and maintenance of the control device
- Other emission limitations or standards specified as exempt by the U.S. EPA

The following table summarizes the units and pollutants subject to CAM and the proposed monitoring method for the affected units.

Table 13-1. Summary of CAM Applicability

FIN	Unit Description	Pollutant Subject to CAM	CAM Type *	Control Device	Proposed Monitoring Method
15	Amine Still Vent	Total HAP	Small	RTO (EPN 5)	CAM-TI-001
2	TEG Dehydrator	VOC and Total HAP	Small	RTO (EPN 5)	CAM-TI-001

* CAM is applicable to pollutants at sources where uncontrolled emissions of the pollutant are greater than the Title V major source threshold. For a pollutant at a source that is subject to CAM, a small CAM source is one where the controlled emissions of a pollutant are less than the Title V major source threshold. A large CAM source is one where the controlled emissions of a pollutant are greater than the Title V major source threshold.

Both the amine unit and TEG dehydrator have uncontrolled emissions greater than major source thresholds. The RTO (EPN 5) will be used to control both sources to maintain the facility's minor source status and to operate within the permitted emission limits. Targa is proposing to use the default CAM option (CAM-TI-001) to monitor the RTO combustion temperature on a daily basis to fulfill the CAM requirement for both the amine units and TEG dehydrator. This will ensure the represented RTO destruction efficiency is achieved, maintaining emissions below major source thresholds and operating within the permitted emission limits.

14. PROFESSIONAL ENGINEER (P.E.) SEAL

The professional engineer (P.E.) seal is included in this section for the proposed project.

FORM PI-1 SECTION X PROFESSIONAL ENGINEER (P.E.) SEAL

I, Paul Greywall, have reviewed the following sections of the attached application for an initial new source review permit submitted by Targa:

Emissions Data

Best Available Control Technology

The capital cost of the project is estimated to be greater than $25,000,000.

The application for initial new source review, as referenced above, was reviewed on the 16th day of February 2012.

Signed: Paul Greywall

Date: 2/16/2012

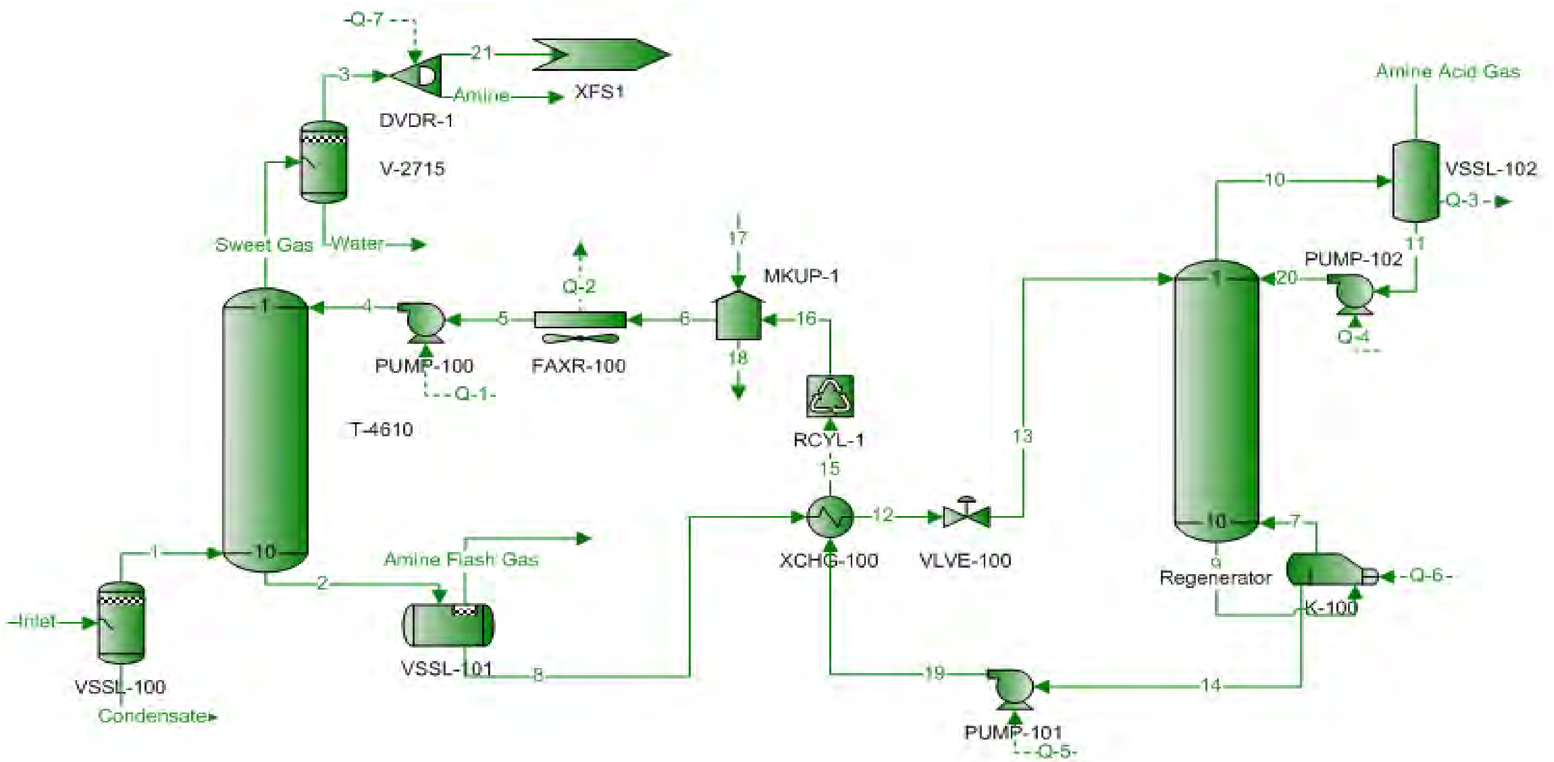
Professional Engineer Registration Number: 105305

STATE OF TEXAS
PAUL F. GREYWALL
105305
LICENSED
PROFESSIONAL ENGINEER

APPENDIX A

ProMax® Simulation Output

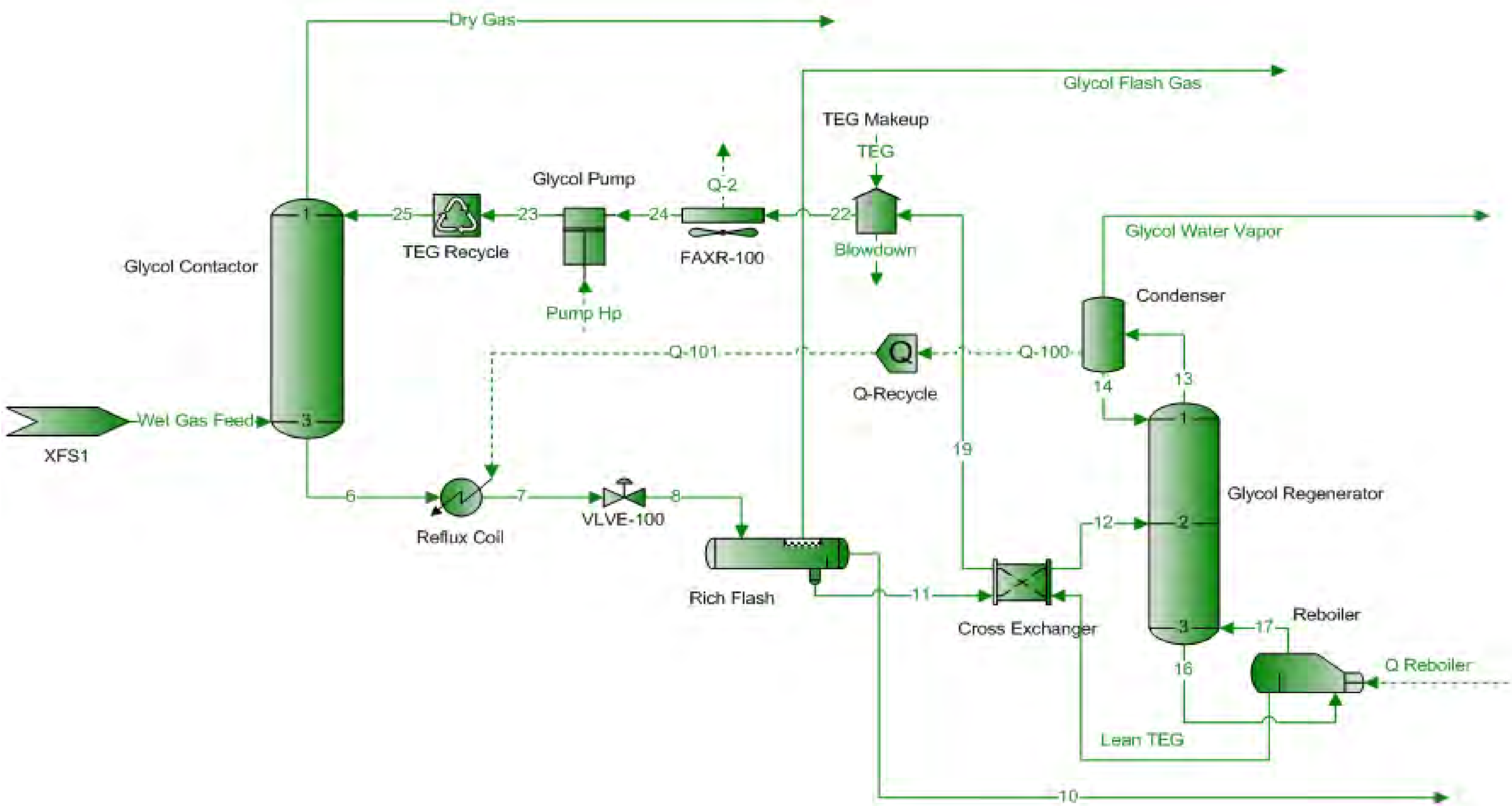
Amine Treating



Process Streams		Amine Acid Gas	Amine Flash Gas	Inlet
Composition	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	VSSL-102	VSSL-101	--
	To Block:	--	--	VSSL-100
Mole Fraction		%	%	%
Nitrogen		0.000246775	0.248362	0.803431*
Carbon Dioxide		93.8400	8.39780	2.71733*
Methane		0.255853	71.5547	79.8759*
Ethane		0.0671402	11.1537	10.0863*
Propane		0.0160832	3.17660	4.09657*
i-Butane		0.00112021	0.276918	0.522235*
n-Butane		0.00454635	0.772234	1.07181*
i-Pentane		0.000274774	0.0921720	0.287705*
n-Pentane		0.000471037	0.122217	0.298821*
n-Hexane		8.53680E-05	0.0263067	0.0906276*
MDEA		1.49914E-08	0.000476035	0*
Piperazine		5.06651E-09	4.93182E-05	0*
Water		5.79292	4.09677	0*
Benzene		0.0103754	0.0212350	0.00540761*
Cyclohexane		0.000479875	0.0245363	0.0190268*
iC7		1.88605E-05	0.0106553	0.0751057*
nC7		5.02279E-06	0.00284667	0.0211298*
Toluene		0.00859850	0.0164290	0.00500705*
iC8		3.25632E-06	0.00193688	0.0157221*
nC8		4.04565E-07	0.000188522	0.00140197*
Ethylbenzene		0.000240429	0.000524431	0.000200282*
p-Xylene		0.00149297	0.00236132	0.000901269*
Isononane		1.87456E-06	0.000580531	0.00350493*
nC9		9.20587E-07	0.000145980	0.000500705*
Decane		1.28739E-06	0.000261060	0.00140197*
Mass Flow		lb/h	lb/h	lb/h
Nitrogen		0.0437418	1.63974	4942.42*
Carbon Dioxide		26131.4	87.1036	26261.1*
Methane		25.9711	270.541	281392*
Ethane		12.7741	79.0430	66600.3*
Propane		4.48741	33.0128	39668.0*
i-Butane		0.411974	3.79331	6665.50*
n-Butane		1.67199	10.5783	13679.9*
i-Pentane		0.125439	1.56730	4558.28*
n-Pentane		0.215037	2.07819	4734.39*
n-Hexane		0.0465486	0.534286	1715.02*
MDEA		1.13034E-05	0.0133691	0*
Piperazine		2.76134E-06	0.00100118	0*
Water		660.339	17.3943	0*
Benzene		5.12801	0.390925	92.7571*
Cyclohexane		0.255540	0.486672	351.636*
iC7		0.0119580	0.251633	1652.62*
nC7		0.00318456	0.0672260	464.938*
Toluene		5.01293	0.356759	101.309*
iC8		0.00235359	0.0521436	394.376*
nC8		0.000292409	0.00507530	35.1673*
Ethylbenzene		0.161509	0.0131218	4.66926*
p-Xylene		1.00290	0.0590827	21.0117*
Isononane		0.00152126	0.0175479	98.7141*
nC9		0.000747082	0.00441258	14.1020*
Decane		0.00115901	0.00875415	43.8040*

Process Streams		Amine Acid Gas	Amine Flash Gas	Inlet
Properties	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	VSSL-102	VSSL-101	--
	To Block:	--	--	VSSL-100
Property	**Units**			
Temperature	°F	120.000	148.892	100*
Pressure	psia	29.6959	79.6959*	950*
Mole Fraction Vapor	%	100	100	100
Mole Fraction Light Liquid	%	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0
Molecular Weight	lb/lbmol	42.4327	21.5976	20.6512
Mass Density	lb/ft^3	0.204451	0.266739	3.93427
Molar Flow	lbmol/h	632.745	23.5681	21959.6
Mass Flow	lb/h	26849.1	509.013	453492
Vapor Volumetric Flow	ft^3/h	131323	1908.28	115267
Liquid Volumetric Flow	gpm	16372.7	237.916	14371.0
Std Vapor Volumetric Flow	MMSCFD	5.76280	0.214649	200*
Std Liquid Volumetric Flow	sgpm	65.5439	2.69633	2596.86
Compressibility		0.990750	0.988068	0.830248
Specific Gravity		1.46509	0.745706	0.713029
API Gravity				
Enthalpy	Btu/h	-1.04112E+08	-1.10711E+06	-8.26860E+08
Mass Enthalpy	Btu/lb	-3877.67	-2175.01	-1823.32
Mass Cp	Btu/(lb*°F)	0.215983	0.472053	0.618622
Ideal Gas CpCv Ratio		1.28013	1.24616	1.25095
Dynamic Viscosity	cP	0.0161538	0.0126621	0.0132174
Kinematic Viscosity	cSt	4.93246	2.96346	0.209730
Thermal Conductivity	Btu/(h*ft*°F)	0.0106611	0.0201292	0.0223543
Surface Tension	lbf/ft			
Net Ideal Gas Heating Value	Btu/ft^3	4.83569	949.022	1065.68
Net Liquid Heating Value	Btu/lb	-55.8135	16585.6	19529.0
Gross Ideal Gas Heating Value	Btu/ft^3	8.19673	1049.86	1176.15
Gross Liquid Heating Value	Btu/lb	-25.7551	18357.4	21558.7

Dehydration



Process Streams		Glycol Flash Gas	Glycol Water Vapor	Wet Gas Feed
Composition	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	Rich Flash	Condenser	XFS1
	To Block:	--	--	Glycol Contactor
Mole Fraction		%	%	%
Nitrogen		0.196861	0.000358836	0.824642
Carbon Dioxide		0.0197680	0.00126829	0.00452168
Methane		63.3773	0.444557	81.9261
Ethane		18.3261	0.430090	10.3418
Propane		10.0939	0.455862	4.20217
i-Butane		1.21526	0.0660641	0.535867
n-Butane		3.06443	0.245600	1.09949
i-Pentane		0.868767	0.121134	0.295291
n-Pentane		0.989680	0.167806	0.306666
n-Hexane		0.297787	0.0871198	0.0930204
Water		1.05601	97.3598	0.217799
Triethylene Glycol		0.000432376	7.43242E-05	0
Benzene		0.0270769	0.135690	0.00522191
Cyclohexane		0.0786381	0.0700645	0.0194945
iC7		0.234987	0.102667	0.0771025
nC7		0.0652468	0.0352452	0.0216917
Toluene		0.0211680	0.183343	0.00486850
iC8		0.0469911	0.0231737	0.0161405
nC8		0.00382784	0.00355417	0.00143926
Ethylbenzene		0.000691875	0.00839197	0.000197949
p-Xylene		0.00298959	0.0377685	0.000878607
Isononane		0.00832221	0.0108131	0.00359800
nC9		0.00115892	0.00195458	0.000513911
Decane		0.00259760	0.00755507	0.00143915
Mass Flow		lb/h	lb/h	lb/h
Nitrogen		0.236827	0.00441512	4940.73
Carbon Dioxide		0.0373607	0.0245157	42.5604
Methane		43.6626	3.13241	281095
Ethane		23.6644	5.68014	66508.5
Propane		19.1144	8.82894	39630.5
i-Butane		3.03331	1.68651	6661.30
n-Butane		7.64885	6.26975	13667.7
i-Pentane		2.69177	3.83864	4556.59
n-Pentane		3.06640	5.31762	4732.10
n-Hexane		1.10203	3.29747	1714.44
Water		0.816984	770.373	839.184
Triethylene Glycol		0.00278842	0.00490233	0
Benzene		0.0908282	4.65529	87.2382
Cyclohexane		0.284211	2.58989	350.894
iC7		1.01117	4.51841	1652.36
nC7		0.280763	1.55116	464.868
Toluene		0.0837580	7.41968	95.9392
iC8		0.230513	1.16265	394.322
nC8		0.0187773	0.178317	35.1619
Ethylbenzene		0.00315438	0.391314	4.49463
p-Xylene		0.0136301	1.76113	19.9497
Isononane		0.0458372	0.609124	98.6951
nC9		0.00638313	0.110105	14.0969
Decane		0.0158718	0.472137	43.7941

Process Streams		Glycol Flash Gas	Glycol Water Vapor	Wet Gas Feed
Properties	Status:	Solved	Solved	Solved
Phase: **Total**	From Block:	Rich Flash	Condenser	XFS1
	To Block:	--	--	Glycol Contactor
Property	**Units**			
Temperature	°F	139.063	210.702	124.415
Pressure	psia	75	14.7	946.906
Mole Fraction Vapor	%	100	100	100
Mole Fraction Light Liquid	%	0	0	0
Mole Fraction Heavy Liquid	%	0	0	0
Molecular Weight	lb/lbmol	24.9539	18.9855	19.9953
Mass Density	lb/ft^3	0.296961	0.0391252	3.51584
Molar Flow	lbmol/h	4.29443	43.9218	21387.5
Mass Flow	lb/h	107.163	833.878	427651
Vapor Volumetric Flow	ft^3/h	360.865	21313.0	121635
Liquid Volumetric Flow	gpm	44.9909	2657.21	15164.9
Std Vapor Volumetric Flow	MMSCFD	0.0391120	0.400024	194.789
Std Liquid Volumetric Flow	sgpm	0.565889	1.75786	2531.65
Compressibility		0.980851	0.991523	0.859145
Specific Gravity		0.861590	0.655518	0.690385
API Gravity				
Enthalpy	Btu/h	-154915	-4.44236E+06	-7.23070E+08
Mass Enthalpy	Btu/lb	-1445.61	-5327.36	-1690.80
Mass Cp	Btu/(lb*°F)	0.494449	0.458094	0.626242
Ideal Gas CpCv Ratio		1.19562	1.29866	1.24383
Dynamic Viscosity	cP	0.0112188	0.0125943	0.0132408
Kinematic Viscosity	cSt	2.35844	20.0953	0.235107
Thermal Conductivity	Btu/(h*ft*°F)	0.0186144	0.0154084	0.0233279
Surface Tension	lbf/ft			
Net Ideal Gas Heating Value	Btu/ft^3	1341.79	73.3448	1093.00
Net Liquid Heating Value	Btu/lb	20302.4	473.045	20689.0
Gross Ideal Gas Heating Value	Btu/ft^3	1473.24	127.985	1206.41
Gross Liquid Heating Value	Btu/lb	22301.2	1565.03	22841.2

APPENDIX B

EPA TANKS 4.09d Reports

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Methanol Tank - Annual Emissions
City:	Dallas-Fort Worth
State:	Texas
Company:	Targa Midstream Services
Type of Tank:	Horizontal Tank
Description:	Methanol Tank

Tank Dimensions

Shell Length (ft):	10.80
Diameter (ft):	4.00
Volume (gallons):	1,000.00
Turnovers:	52.00
Net Throughput(gal/yr):	52,000.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Dallas-Fort Worth, Texas (Avg Atmospheric Pressure = 14.44 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Methanol Tank - Annual Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	Jan	60.88	53.57	68.19	67.65	1.4825	1.1743	1.8575	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Feb	63.95	55.57	72.33	67.65	1.6314	1.2524	2.1043	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Mar	69.22	59.56	78.87	67.65	1.9163	1.4224	2.5497	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Apr	74.27	63.68	84.86	67.65	2.2285	1.6176	3.0257	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	May	78.34	67.20	89.49	67.65	2.5112	1.8027	3.4436	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Jun	82.85	70.62	95.08	67.65	2.8587	1.9994	4.0127	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Jul	84.92	72.47	97.38	67.65	3.0313	2.1126	4.2684	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Aug	83.85	72.15	95.56	67.65	2.9412	2.0930	4.0645	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Sep	78.95	68.96	88.95	67.65	2.5559	1.9014	3.3927	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Oct	73.13	63.99	82.27	67.65	2.1549	1.6335	2.8118	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Nov	66.82	59.20	74.44	67.65	1.7820	1.4062	2.2403	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13
Methyl alcohol	Dec	62.11	55.11	69.12	67.65	1.5409	1.2342	1.9105	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Methanol Tank - Annual Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	2.0527	2.4159	3.8124	4.9593	6.3516	8.1029	9.2743	8.3282	5.6273	4.2051	2.6245	2.0604
Vapor Space Volume (cu ft):	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438
Vapor Density (lb/cu ft):	0.0085	0.0093	0.0108	0.0125	0.0139	0.0157	0.0166	0.0162	0.0142	0.0121	0.0101	0.0088
Vapor Space Expansion Factor:	0.1042	0.1259	0.1582	0.1897	0.2153	0.2588	0.2752	0.2523	0.1947	0.1596	0.1191	0.1014
Vented Vapor Saturation Factor:	0.8642	0.8526	0.8312	0.8089	0.7898	0.7674	0.7568	0.7623	0.7868	0.8141	0.8411	0.8596
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438	86.4438
Tank Diameter (ft):	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000
Effective Diameter (ft):	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183	7.4183
Vapor Space Outage (ft):	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
Tank Shell Length (ft):	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000	10.8000
Vapor Density												
Vapor Density (lb/cu ft):	0.0085	0.0093	0.0108	0.0125	0.0139	0.0157	0.0166	0.0162	0.0142	0.0121	0.0101	0.0088
Vapor Molecular Weight (lb/lb-mole):	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.4825	1.6314	1.9163	2.2285	2.5112	2.8587	3.0313	2.9412	2.5559	2.1549	1.7820	1.5409
Daily Avg. Liquid Surface Temp. (deg. R):	520.5484	523.6207	528.8854	533.9363	538.0142	542.5222	544.5919	543.5239	538.6224	532.8026	526.4924	521.7839
Daily Average Ambient Temp. (deg. F):	43.4000	47.9000	56.7000	65.5000	72.7500	80.9500	85.3000	84.9000	77.3500	67.1500	56.1000	46.9000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	914.0549	1,170.0918	1,496.5626	1,772.9048	1,981.0339	2,192.0184	2,228.5045	2,019.4236	1,649.1695	1,336.9758	997.4969	842.6691
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.1042	0.1259	0.1582	0.1897	0.2153	0.2588	0.2752	0.2523	0.1947	0.1596	0.1191	0.1014
Daily Vapor Temperature Range (deg. R):	29.2285	33.5318	38.6120	42.3583	44.5692	48.9113	49.8230	46.8057	39.9834	36.5591	30.4902	28.0052
Daily Vapor Pressure Range (psia):	0.6832	0.8519	1.1273	1.4081	1.6409	2.0133	2.1558	1.9715	1.4913	1.1783	0.8341	0.6763
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.4825	1.6314	1.9163	2.2285	2.5112	2.8587	3.0313	2.9412	2.5559	2.1549	1.7820	1.5409
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.1743	1.2524	1.4224	1.6176	1.8027	1.9994	2.1126	2.0930	1.9014	1.6335	1.4062	1.2342
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	1.8575	2.1043	2.5497	3.0257	3.4436	4.0127	4.2684	4.0645	3.3927	2.8118	2.2403	1.9105
Daily Avg. Liquid Surface Temp. (deg R):	520.5484	523.6207	528.8854	533.9363	538.0142	542.5222	544.5919	543.5239	538.6224	532.8026	526.4924	521.7839
Daily Min. Liquid Surface Temp. (deg R):	513.2413	515.2377	519.2324	523.3467	526.8718	530.2944	532.1361	531.8225	528.6266	523.6628	518.8699	514.7826
Daily Max. Liquid Surface Temp. (deg R):	527.8556	532.0036	538.5384	544.5259	549.1565	554.7500	557.0476	555.2253	548.6183	541.9424	534.1149	528.7852
Daily Ambient Temp. Range (deg. R):	21.4000	22.0000	22.2000	21.6000	20.3000	21.9000	22.4000	22.6000	20.9000	22.7000	21.4000	21.2000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.8642	0.8526	0.8312	0.8089	0.7898	0.7674	0.7568	0.7623	0.7868	0.8141	0.8411	0.8596
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	1.4825	1.6314	1.9163	2.2285	2.5112	2.8587	3.0313	2.9412	2.5559	2.1549	1.7820	1.5409
Vapor Space Outage (ft):	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000	2.0000
Working Losses (lb):	3.6441	4.0101	4.7105	5.4779	6.1728	7.0268	7.4513	7.2296	6.2826	5.2970	4.3802	3.7877
Vapor Molecular Weight (lb/lb-mole):	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400	32.0400
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	1.4825	1.6314	1.9163	2.2285	2.5112	2.8587	3.0313	2.9412	2.5559	2.1549	1.7820	1.5409
Net Throughput (gal/mo.):	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333	4,333.3333
Annual Turnovers:	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000	52.0000
Turnover Factor:	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436	0.7436
Tank Diameter (ft):	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000	4.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	5.6968	6.4260	8.5229	10.4372	12.5244	15.1297	16.7256	15.5578	11.9099	9.5021	7.0047	5.8481

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

Methanol Tank - Annual Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	65.47	59.81	125.29

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Methanol - Hourly Emissions
City:	Dallas-Fort Worth
State:	Texas
Company:	Targa Midstream Services
Type of Tank:	Horizontal Tank
Description:	Methanol Tank

Tank Dimensions

Shell Length (ft):	10.80
Diameter (ft):	4.00
Volume (gallons):	1,000.00
Turnovers:	4.43
Net Throughput(gal/yr):	4,429.00
Is Tank Heated (y/n):	N
Is Tank Underground (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Dallas-Fort Worth, Texas (Avg Atmospheric Pressure = 14.44 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Methanol - Hourly Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Methyl alcohol	Jul	84.92	72.47	97.38	67.65	3.0313	2.1126	4.2684	32.0400			32.04	Option 2: A=7.897, B=1474.08, C=229.13

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Methanol - Hourly Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):							9.2743					
Vapor Space Volume (cu ft):							86.4438					
Vapor Density (lb/cu ft):							0.0166					
Vapor Space Expansion Factor:							0.2752					
Vented Vapor Saturation Factor:							0.7568					
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):							86.4438					
Tank Diameter (ft):							4.0000					
Effective Diameter (ft):							7.4183					
Vapor Space Outage (ft):							2.0000					
Tank Shell Length (ft):							10.8000					
Vapor Density												
Vapor Density (lb/cu ft):							0.0166					
Vapor Molecular Weight (lb/lb-mole):							32.0400					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.0313					
Daily Avg. Liquid Surface Temp. (deg. R):							544.5919					
Daily Average Ambient Temp. (deg. F):							85.3000					
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):							10.731					
Liquid Bulk Temperature (deg. R):							527.3183					
Tank Paint Solar Absorptance (Shell):							0.5400					
Daily Total Solar Insulation Factor (Btu/sqft day):							2,228.5045					
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:							0.2752					
Daily Vapor Temperature Range (deg. R):							49.8230					
Daily Vapor Pressure Range (psia):							2.1558					
Breather Vent Press. Setting Range(psia):							0.0600					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.0313					
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):							2.1126					
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):							4.2684					
Daily Avg. Liquid Surface Temp. (deg R):							544.5919					
Daily Min. Liquid Surface Temp. (deg R):							532.1361					
Daily Max. Liquid Surface Temp. (deg R):							557.0476					
Daily Ambient Temp. Range (deg. R):							22.4000					
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:							0.7568					
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):							3.0313					
Vapor Space Outage (ft):							2.0000					
Working Losses (lb):							10.2419					
Vapor Molecular Weight (lb/lb-mole):							32.0400					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.0313					
Net Throughput (gal/mo.):							4,429.0000					
Annual Turnovers:							4.4290					
Turnover Factor:							1.0000					
Tank Diameter (ft):							4.0000					
Working Loss Product Factor:							1.0000					
Total Losses (lb):							19.5163					

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

Methanol - Hourly Emissions - Horizontal Tank
Dallas-Fort Worth, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Methyl alcohol	10.24	9.27	19.52

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification	
User Identification:	Condesate Tank - Annual Emissions
City:	Dallas-Fort Worth
State:	Texas
Company:	Targa Midstream Services
Type of Tank:	Vertical Fixed Roof Tank
Description:	L.P. Condensate Tanks
Tank Dimensions	
Shell Height (ft):	15.00
Diameter (ft):	10.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	7.50
Volume (gallons):	8,820.00
Turnovers:	47.17
Net Throughput(gal/yr):	416,000.00
Is Tank Heated (y/n):	N
Paint Characteristics	
Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good
Roof Characteristics	
Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.00
Breather Vent Settings	
Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Dallas-Fort Worth, Texas (Avg Atmospheric Pressure = 14.44 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Condesate Tank - Annual Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Condensate	Jan	60.88	53.57	68.19	67.65	2.0635	1.6388	2.5151	69.2877			100.97	
Benzene						1.1966	0.9745	1.4592	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						16.0831	11.9999	20.1021	58.1220	0.0258	0.2930	58.12	Option 1: VP60 = 15.6 VP70 = 21.1
Decane (-n)						0.0340	0.0288	0.0402	142.2900	0.0603	0.0014	142.29	Option 1: VP60 = .033211 VP70 = .041762
Ethane						16.0831	11.9999	20.1021	60.0690	0.0004	0.0045	60.07	Option 1: VP60 = 15.6 VP70 = 21.1
Ethylbenzene						0.1119	0.0865	0.1435	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.6278	0.5032	0.7784	100.2000	0.2499	0.1108	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						1.9576	1.6146	2.3582	86.1700	0.1085	0.1499	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0668	0.0563	0.0799	128.2600	0.1166	0.0055	128.26	Option 1: VP60 = .065278 VP70 = .08309
Octane (-n)						0.1492	0.1242	0.1805	114.2300	0.3008	0.0317	114.23	Option 1: VP60 = .145444 VP70 = .188224
Pentane (-n)						6.9700	5.9160	8.1746	72.1500	0.0653	0.3214	72.15	Option 3: A=27691, B=7.558
Propane						16.0831	11.9999	20.1021	44.0960	0.0059	0.0670	44.10	Option 1: VP60 = 15.6 VP70 = 21.1
Toluene						0.3393	0.2694	0.4239	92.1300	0.0364	0.0087	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.0932	0.0718	0.1198	106.1700	0.0241	0.0016	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Feb	63.95	55.57	72.33	67.65	2.2497	1.7522	2.7878	69.1761			100.97	
Benzene						1.3018	1.0314	1.6284	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						17.7729	13.1179	22.4068	58.1220	0.0258	0.2975	58.12	Option 1: VP60 = 15.6 VP70 = 21.1
Decane (-n)						0.0366	0.0302	0.0443	142.2900	0.0603	0.0014	142.29	Option 1: VP60 = .033211 VP70 = .041762
Ethane						17.7729	13.1179	22.4068	60.0690	0.0004	0.0046	60.07	Option 1: VP60 = 15.6 VP70 = 21.1
Ethylbenzene						0.1244	0.0929	0.1647	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.6877	0.5349	0.8772	100.2000	0.2499	0.1115	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.1186	1.7030	2.6140	86.1700	0.1085	0.1491	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0723	0.0591	0.0884	128.2600	0.1166	0.0055	128.26	Option 1: VP60 = .065278 VP70 = .08309
Octane (-n)						0.1623	0.1308	0.2011	114.2300	0.3008	0.0317	114.23	Option 1: VP60 = .145444 VP70 = .188224
Pentane (-n)						7.4572	6.1899	8.9314	72.1500	0.0653	0.3159	72.15	Option 3: A=27691, B=7.558
Propane						17.7729	13.1179	22.4068	44.0960	0.0059	0.0680	44.10	Option 1: VP60 = 15.6 VP70 = 21.1
Toluene						0.3729	0.2872	0.4795	92.1300	0.0364	0.0088	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1037	0.0772	0.1377	106.1700	0.0241	0.0016	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Mar	69.22	59.56	78.87	67.65	2.5812	1.9852	3.2430	69.0900			100.97	
Benzene						1.4998	1.1538	1.9275	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						20.6685	15.3549	26.0663	58.1220	0.0258	0.3019	58.12	Option 1: VP60 = 15.6 VP70 = 21.1
Decane (-n)						0.0411	0.0329	0.0513	142.2900	0.0603	0.0014	142.29	Option 1: VP60 = .033211 VP70 = .041762
Ethane						20.6685	15.3549	26.0663	60.0690	0.0004	0.0047	60.07	Option 1: VP60 = 15.6 VP70 = 21.1
Ethylbenzene						0.1485	0.1069	0.2034	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.8020	0.6036	1.0549	100.2000	0.2499	0.1135	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.4197	1.8917	3.0626	86.1700	0.1085	0.1486	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0817	0.0647	0.1032	128.2600	0.1166	0.0054	128.26	Option 1: VP60 = .065278 VP70 = .08309
Octane (-n)						0.1849	0.1440	0.2373	114.2300	0.3008	0.0315	114.23	Option 1: VP60 = .145444 VP70 = .188224
Pentane (-n)						8.3573	6.7695	10.2400	72.1500	0.0653	0.3090	72.15	Option 3: A=27691, B=7.558
Propane						20.6685	15.3549	26.0663	44.0960	0.0059	0.0690	44.10	Option 1: VP60 = 15.6 VP70 = 21.1
Toluene						0.4372	0.3257	0.5794	92.1300	0.0364	0.0090	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1241	0.0890	0.1705	106.1700	0.0241	0.0017	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Apr	74.27	63.68	84.86	67.65	2.9194	2.2329	3.6864	69.1176			100.97	
Benzene						1.7126	1.2921	2.2400	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						23.4891	17.6222	29.3707	58.1220	0.0258	0.3032	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0463	0.0364	0.0591	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						23.4891	17.6222	29.3707	60.0690	0.0004	0.0047	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.1754	0.1232	0.2455	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.9268	0.6822	1.2443	100.2000	0.2499	0.1159	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.7407	2.1038	3.5268	86.1700	0.1085	0.1487	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0928	0.0718	0.1198	128.2600	0.1166	0.0054	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2118	0.1612	0.2784	114.2300	0.3008	0.0319	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						9.3032	7.4127	11.5732	72.1500	0.0653	0.3040	72.15	Option 3: A=27691, B=7.558
Propane						23.4891	17.6222	29.3707	44.0960	0.0059	0.0693	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.5074	0.3698	0.6858	92.1300	0.0364	0.0092	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1468	0.1027	0.2061	106.1700	0.0241	0.0018	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	May	78.34	67.20	89.49	67.65	3.2054	2.4525	4.0483	69.1918			100.97	
Benzene						1.9020	1.4213	2.5091	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						25.7727	19.5610	31.9176	58.1220	0.0258	0.3027	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0507	0.0394	0.0653	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						25.7727	19.5610	31.9176	60.0690	0.0004	0.0047	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2000	0.1389	0.2829	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.0396	0.7565	1.4103	100.2000	0.2499	0.1183	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.0244	2.3007	3.9237	86.1700	0.1085	0.1493	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1020	0.0781	0.1331	128.2600	0.1166	0.0054	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2344	0.1763	0.3116	114.2300	0.3008	0.0321	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						10.1295	8.0031	12.6989	72.1500	0.0653	0.3011	72.15	Option 3: A=27691, B=7.558
Propane						25.7727	19.5610	31.9176	44.0960	0.0059	0.0692	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.5708	0.4116	0.7789	92.1300	0.0364	0.0095	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1676	0.1159	0.2379	106.1700	0.0241	0.0018	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Jun	82.85	70.62	95.08	67.65	3.5351	2.6734	4.5159	69.3406			100.97	
Benzene						2.1311	1.5568	2.8690	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						28.2687	21.4497	35.0448	58.1220	0.0258	0.3004	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0564	0.0424	0.0747	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						28.2687	21.4497	35.0448	60.0690	0.0004	0.0047	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2306	0.1557	0.3344	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.1779	0.8353	1.6360	100.2000	0.2499	0.1212	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.3655	2.5060	4.4506	86.1700	0.1085	0.1504	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1140	0.0845	0.1533	128.2600	0.1166	0.0055	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2640	0.1917	0.3623	114.2300	0.3008	0.0327	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						11.1121	8.6129	14.1764	72.1500	0.0653	0.2989	72.15	Option 3: A=27691, B=7.558
Propane						28.2687	21.4497	35.0448	44.0960	0.0059	0.0687	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.6485	0.4559	0.9053	92.1300	0.0364	0.0097	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1935	0.1301	0.2818	106.1700	0.0241	0.0019	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Jul	84.92	72.47	97.38	67.65	3.6915	2.7967	4.7163	69.4262			100.97	
Benzene						2.2436	1.6341	3.0285	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						29.4070	22.4810	36.3315	58.1220	0.0258	0.2989	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0592	0.0444	0.0786	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						29.4070	22.4810	36.3315	60.0690	0.0004	0.0046	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2460	0.1654	0.3578	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.2465	0.8805	1.7374	100.2000	0.2499	0.1227	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.5322	2.6225	4.6829	86.1700	0.1085	0.1509	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1200	0.0887	0.1617	128.2600	0.1166	0.0055	128.26	Option 1: VP70 = .08309 VP80 = .105762

Octane (-n)						0.2788	0.2019	0.3836	114.2300	0.3008	0.0330	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						11.5886	8.9565	14.8225	72.1500	0.0653	0.2981	72.15	Option 3: A=27691, B=7.558
Propane						29.4070	22.4810	36.3315	44.0960	0.0059	0.0684	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.6871	0.4814	0.9620	92.1300	0.0364	0.0099	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.2065	0.1383	0.3017	106.1700	0.0241	0.0020	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Aug	83.85	72.15	95.56	67.65	3.6104	2.7756	4.5569	69.3813			100.97	
Benzene						2.1850	1.6207	2.9014	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						28.8197	22.3054	35.3110	58.1220	0.0258	0.2997	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0577	0.0441	0.0755	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						28.8197	22.3054	35.3110	60.0690	0.0004	0.0046	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2379	0.1637	0.3392	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.2107	0.8727	1.6566	100.2000	0.2499	0.1219	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.4454	2.6024	4.4978	86.1700	0.1085	0.1506	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1169	0.0880	0.1550	128.2600	0.1166	0.0055	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2712	0.2001	0.3667	114.2300	0.3008	0.0329	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						11.3407	8.8972	14.3082	72.1500	0.0653	0.2985	72.15	Option 3: A=27691, B=7.558
Propane						28.8197	22.3054	35.3110	44.0960	0.0059	0.0685	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.6669	0.4769	0.9168	92.1300	0.0364	0.0098	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1997	0.1369	0.2858	106.1700	0.0241	0.0019	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Sep	78.95	68.96	88.95	67.65	3.2491	2.5645	4.0054	69.2060			100.97	
Benzene						1.9317	1.4895	2.4765	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						26.1134	20.5261	31.6216	58.1220	0.0258	0.3025	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0514	0.0409	0.0646	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						26.1134	20.5261	31.6216	60.0690	0.0004	0.0047	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2039	0.1473	0.2783	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.0574	0.7960	1.3900	100.2000	0.2499	0.1186	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.0687	2.4041	3.8758	86.1700	0.1085	0.1495	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1034	0.0812	0.1316	128.2600	0.1166	0.0054	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2378	0.1838	0.3077	114.2300	0.3008	0.0321	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						10.2578	8.3111	12.5637	72.1500	0.0653	0.3008	72.15	Option 3: A=27691, B=7.558
Propane						26.1134	20.5261	31.6216	44.0960	0.0059	0.0692	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.5808	0.4338	0.7676	92.1300	0.0364	0.0095	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1709	0.1230	0.2340	106.1700	0.0241	0.0018	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Oct	73.13	63.99	82.27	67.65	2.8419	2.2523	3.4919	69.1043			100.97	
Benzene						1.6628	1.3033	2.1004	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						22.8543	17.7961	27.9498	58.1220	0.0258	0.3031	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0451	0.0366	0.0556	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						22.8543	17.7961	27.9498	60.0690	0.0004	0.0047	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.1690	0.1246	0.2265	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.8974	0.6886	1.1592	100.2000	0.2499	0.1153	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.6658	2.1209	3.3199	86.1700	0.1085	0.1487	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0902	0.0724	0.1123	128.2600	0.1166	0.0054	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2056	0.1625	0.2599	114.2300	0.3008	0.0318	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						9.0836	7.4641	10.9815	72.1500	0.0653	0.3050	72.15	Option 3: A=27691, B=7.558
Propane						22.8543	17.7961	27.9498	44.0960	0.0059	0.0693	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.4909	0.3734	0.6380	92.1300	0.0364	0.0092	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1414	0.1039	0.1900	106.1700	0.0241	0.0018	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Nov	66.82	59.20	74.44	67.65	2.4285	1.9637	2.9317	69.1147			100.97	
Benzene						1.4069	1.1422	1.7205	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						19.3523	15.1519	23.5892	58.1220	0.0258	0.3003	58.12	Option 1: VP60 = 15.6 VP70 = 21.1
Decane (-n)						0.0390	0.0327	0.0465	142.2900	0.0603	0.0014	142.29	Option 1: VP60 = .033211 VP70 = .041762
Ethane						19.3523	15.1519	23.5892	60.0690	0.0004	0.0047	60.07	Option 1: VP60 = 15.6 VP70 = 21.1
Ethylbenzene						0.1371	0.1055	0.1764	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.7482	0.5970	0.9315	100.2000	0.2499	0.1125	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.2788	1.8739	2.7526	86.1700	0.1085	0.1487	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0774	0.0642	0.0932	128.2600	0.1166	0.0054	128.26	Option 1: VP60 = .065278 VP70 = .08309
Octane (-n)						0.1746	0.1428	0.2128	114.2300	0.3008	0.0316	114.23	Option 1: VP60 = .145444 VP70 = .188224
Pentane (-n)						7.9377	6.7151	9.3382	72.1500	0.0653	0.3118	72.15	Option 3: A=27691, B=7.558
Propane						19.3523	15.1519	23.5892	44.0960	0.0059	0.0687	44.10	Option 1: VP60 = 15.6 VP70 = 21.1
Toluene						0.4069	0.3220	0.5100	92.1300	0.0364	0.0089	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.1144	0.0879	0.1476	106.1700	0.0241	0.0017	106.17	Option 2: A=7.009, B=1462.266, C=215.11
Condensate	Dec	62.11	55.11	69.12	67.65	2.1378	1.7262	2.5748	69.2365			100.97	
Benzene						1.2380	1.0182	1.4958	78.1100	0.0050	0.0043	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						16.7626	12.8631	20.6134	58.1220	0.0258	0.2950	58.12	Option 1: VP60 = 15.6 VP70 = 21.1
Decane (-n)						0.0350	0.0299	0.0410	142.2900	0.0603	0.0014	142.29	Option 1: VP60 = .033211 VP70 = .041762
Ethane						16.7626	12.8631	20.6134	60.0690	0.0004	0.0046	60.07	Option 1: VP60 = 15.6 VP70 = 21.1
Ethylbenzene						0.1168	0.0914	0.1480	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						0.6513	0.5275	0.7997	100.2000	0.2499	0.1110	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						2.0211	1.6825	2.4137	86.1700	0.1085	0.1495	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.0690	0.0584	0.0815	128.2600	0.1166	0.0055	128.26	Option 1: VP60 = .065278 VP70 = .08309
Octane (-n)						0.1545	0.1293	0.1844	114.2300	0.3008	0.0317	114.23	Option 1: VP60 = .145444 VP70 = .188224
Pentane (-n)						7.1627	6.1266	8.3394	72.1500	0.0653	0.3191	72.15	Option 3: A=27691, B=7.558
Propane						16.7626	12.8631	20.6134	44.0960	0.0059	0.0675	44.10	Option 1: VP60 = 15.6 VP70 = 21.1
Toluene						0.3525	0.2830	0.4359	92.1300	0.0364	0.0088	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.0973	0.0760	0.1237	106.1700	0.0241	0.0016	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Condesate Tank - Annual Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):	31.3504	34.7385	49.2767	57.6902	67.7143	78.4460	85.8313	78.9136	59.2816	50.1575	35.6589	30.7296
Vapor Space Volume (cu ft):	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486
Vapor Density (lb/cu ft):	0.0256	0.0277	0.0314	0.0352	0.0384	0.0421	0.0439	0.0429	0.0389	0.0343	0.0297	0.0264
Vapor Space Expansion Factor:	0.1221	0.1441	0.1740	0.2003	0.2195	0.2536	0.2645	0.2450	0.1976	0.1703	0.1335	0.1178
Vented Vapor Saturation Factor:	0.5494	0.5279	0.4936	0.4629	0.4397	0.4158	0.4053	0.4107	0.4364	0.4696	0.5088	0.5406
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486	589.0486
Tank Diameter (ft):	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000
Vapor Space Outage (ft):	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000
Tank Shell Height (ft):	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000
Average Liquid Height (ft):	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000
Roof Outage (ft):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Roof Outage (Cone Roof)												
Roof Outage (ft):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Roof Height (ft):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Roof Slope (ft/ft):	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000
Shell Radius (ft):	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000	5.0000
Vapor Density												
Vapor Density (lb/cu ft):	0.0256	0.0277	0.0314	0.0352	0.0384	0.0421	0.0439	0.0429	0.0389	0.0343	0.0297	0.0264
Vapor Molecular Weight (lb/lb-mole):	69.2877	69.1761	69.0900	69.1176	69.1918	69.3406	69.4262	69.3813	69.2060	69.1043	69.1147	69.2365
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0635	2.2497	2.5812	2.9194	3.2054	3.5351	3.6915	3.6104	3.2491	2.8419	2.4285	2.1378
Daily Avg. Liquid Surface Temp. (deg. R):	520.5484	523.6207	528.8854	533.9363	538.0142	542.5222	544.5919	543.5239	538.6224	532.8026	526.4924	521.7839
Daily Average Ambient Temp. (deg. F):	43.4000	47.9000	56.7000	65.5000	72.7500	80.9500	85.3000	84.9000	77.3500	67.1500	56.1000	46.9000
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731	10.731
Liquid Bulk Temperature (deg. R):	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183	527.3183
Tank Paint Solar Absorptance (Shell):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Tank Paint Solar Absorptance (Roof):	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400	0.5400
Daily Total Solar Insulation Factor (Btu/sqft day):	914.0549	1,170.0918	1,496.5626	1,772.9048	1,981.0339	2,192.0184	2,228.5045	2,019.4236	1,649.1695	1,336.9758	997.4969	842.6691
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:	0.1221	0.1441	0.1740	0.2003	0.2195	0.2536	0.2645	0.2450	0.1976	0.1703	0.1335	0.1178
Daily Vapor Temperature Range (deg. R):	29.2285	33.5318	38.6120	42.3583	44.5692	48.9113	49.8230	46.8057	39.9834	36.5591	30.4902	28.0052
Daily Vapor Pressure Range (psia):	0.8763	1.0355	1.2578	1.4535	1.5959	1.8425	1.9195	1.7813	1.4409	1.2396	0.9680	0.8485
Breather Vent Press. Setting Range(psia):	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600	0.0600
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0635	2.2497	2.5812	2.9194	3.2054	3.5351	3.6915	3.6104	3.2491	2.8419	2.4285	2.1378
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):	1.6388	1.7522	1.9852	2.2329	2.4525	2.6734	2.7967	2.7756	2.5645	2.2523	1.9637	1.7262
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):	2.5151	2.7878	3.2430	3.6864	4.0483	4.5159	4.7163	4.5569	4.0054	3.4919	2.9317	2.5748
Daily Avg. Liquid Surface Temp. (deg R):	520.5484	523.6207	528.8854	533.9363	538.0142	542.5222	544.5919	543.5239	538.6224	532.8026	526.4924	521.7839
Daily Min. Liquid Surface Temp. (deg R):	513.2413	515.2377	519.2324	523.3467	526.8718	530.2944	532.1361	531.8225	528.6266	523.6628	518.8699	514.7826
Daily Max. Liquid Surface Temp. (deg R):	527.8556	532.0036	538.5384	544.5259	549.1565	554.7500	557.0476	555.2253	548.6183	541.9424	534.1149	528.7852
Daily Ambient Temp. Range (deg. R):	21.4000	22.0000	22.2000	21.6000	20.3000	21.9000	22.4000	22.6000	20.9000	22.7000	21.4000	21.2000
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:	0.5494	0.5279	0.4936	0.4629	0.4397	0.4158	0.4053	0.4107	0.4364	0.4696	0.5088	0.5406
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):	2.0635	2.2497	2.5812	2.9194	3.2054	3.5351	3.6915	3.6104	3.2491	2.8419	2.4285	2.1378
Vapor Space Outage (ft):	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000	7.5000
Working Losses (lb):	94.7312	103.1109	118.1586	133.6942	146.9489	162.4101	169.8037	165.9658	148.9807	130.1194	111.2075	98.0668
Vapor Molecular Weight (lb/lb-mole):	69.2877	69.1761	69.0900	69.1176	69.1918	69.3406	69.4262	69.3813	69.2060	69.1043	69.1147	69.2365
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):	2.0635	2.2497	2.5812	2.9194	3.2054	3.5351	3.6915	3.6104	3.2491	2.8419	2.4285	2.1378
Net Throughput (gal/mo.):	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667	34,666.6667
Annual Turnovers:	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660	47.1660
Turnover Factor:	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027	0.8027
Maximum Liquid Volume (gal):	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000	8,820.0000
Maximum Liquid Height (ft):	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000	15.0000
Tank Diameter (ft):	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000	10.0000
Working Loss Product Factor:	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000	1.0000
Total Losses (lb):	126.0815	137.8494	167.4353	191.3845	214.6632	240.8561	255.6350	244.8794	208.2623	180.2769	146.8664	128.7964

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

Condesate Tank - Annual Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Condensate	1,583.20	659.79	2,242.99
Benzene	6.87	2.87	9.75
Butane	475.26	198.17	673.43
Decane (-n)	2.23	0.93	3.16
Ethane	7.37	3.07	10.44
Ethylbenzene	0.13	0.06	0.19
Heptane (-n)	185.12	77.54	262.66
Hexane (-n)	236.82	98.75	335.57
Nonane (-n)	8.63	3.60	12.23
Octane (-n)	50.90	21.26	72.16
Pentane (-n)	483.58	200.84	684.42
Propane	108.68	45.32	154.00
Toluene	14.77	6.19	20.96
Xylenes (mixed isomers)	2.84	1.19	4.03

TANKS 4.0.9d
Emissions Report - Detail Format
Tank Indentification and Physical Characteristics

Identification

User Identification:	Condensate - Hourly Emissions
City:	Dallas-Fort Worth
State:	Texas
Company:	Targa Midstream Services
Type of Tank:	Vertical Fixed Roof Tank
Description:	L.P. Condensate Tanks

Tank Dimensions

Shell Height (ft):	15.00
Diameter (ft):	10.00
Liquid Height (ft) :	15.00
Avg. Liquid Height (ft):	7.50
Volume (gallons):	8,820.00
Turnovers:	4.02
Net Throughput(gal/yr):	35,429.00
Is Tank Heated (y/n):	N

Paint Characteristics

Shell Color/Shade:	Gray/Light
Shell Condition	Good
Roof Color/Shade:	Gray/Light
Roof Condition:	Good

Roof Characteristics

Type:	Cone
Height (ft)	0.00
Slope (ft/ft) (Cone Roof)	0.00

Breather Vent Settings

Vacuum Settings (psig):	-0.03
Pressure Settings (psig)	0.03

Meterological Data used in Emissions Calculations: Dallas-Fort Worth, Texas (Avg Atmospheric Pressure = 14.44 psia)

TANKS 4.0.9d
Emissions Report - Detail Format
Liquid Contents of Storage Tank

Condensate - Hourly Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

Mixture/Component	Month	Daily Liquid Surf. Temperature (deg F) Avg.	Min.	Max.	Liquid Bulk Temp (deg F)	Vapor Pressure (psia) Avg.	Min.	Max.	Vapor Mol. Weight.	Liquid Mass Fract.	Vapor Mass Fract.	Mol. Weight	Basis for Vapor Pressure Calculations
Condensate	Jul	84.92	72.47	97.38	67.65	3.6915	2.7967	4.7163	69.4262			100.97	
Benzene						2.2436	1.6341	3.0285	78.1100	0.0050	0.0044	78.11	Option 2: A=6.905, B=1211.033, C=220.79
Butane						29.4070	22.4810	36.3315	58.1220	0.0258	0.2989	58.12	Option 1: VP70 = 21.1 VP80 = 26.7
Decane (-n)						0.0592	0.0444	0.0786	142.2900	0.0603	0.0014	142.29	Option 1: VP70 = .041762 VP80 = .052515
Ethane						29.4070	22.4810	36.3315	60.0690	0.0004	0.0046	60.07	Option 1: VP70 = 21.1 VP80 = 26.7
Ethylbenzene						0.2460	0.1654	0.3578	106.1700	0.0009	0.0001	106.17	Option 2: A=6.975, B=1424.255, C=213.21
Heptane (-n)						1.2465	0.8805	1.7374	100.2000	0.2499	0.1227	100.20	Option 3: A=37358, B=8.2585
Hexane (-n)						3.5322	2.6225	4.6829	86.1700	0.1085	0.1509	86.17	Option 2: A=6.876, B=1171.17, C=224.41
Nonane (-n)						0.1200	0.0887	0.1617	128.2600	0.1166	0.0055	128.26	Option 1: VP70 = .08309 VP80 = .105762
Octane (-n)						0.2788	0.2019	0.3836	114.2300	0.3008	0.0330	114.23	Option 1: VP70 = .188224 VP80 = .243586
Pentane (-n)						11.5886	8.9565	14.8225	72.1500	0.0653	0.2981	72.15	Option 3: A=27691, B=7.558
Propane						29.4070	22.4810	36.3315	44.0960	0.0059	0.0684	44.10	Option 1: VP70 = 21.1 VP80 = 26.7
Toluene						0.6871	0.4814	0.9620	92.1300	0.0364	0.0099	92.13	Option 2: A=6.954, B=1344.8, C=219.48
Xylenes (mixed isomers)						0.2065	0.1383	0.3017	106.1700	0.0241	0.0020	106.17	Option 2: A=7.009, B=1462.266, C=215.11

TANKS 4.0.9d
Emissions Report - Detail Format
Detail Calculations (AP-42)

Condensate - Hourly Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

Month:	January	February	March	April	May	June	July	August	September	October	November	December
Standing Losses (lb):							85.8313					
Vapor Space Volume (cu ft):							589.0486					
Vapor Density (lb/cu ft):							0.0439					
Vapor Space Expansion Factor:							0.2645					
Vented Vapor Saturation Factor:							0.4053					
Tank Vapor Space Volume:												
Vapor Space Volume (cu ft):							589.0486					
Tank Diameter (ft):							10.0000					
Vapor Space Outage (ft):							7.5000					
Tank Shell Height (ft):							15.0000					
Average Liquid Height (ft):							7.5000					
Roof Outage (ft):							0.0000					
Roof Outage (Cone Roof)												
Roof Outage (ft):							0.0000					
Roof Height (ft):							0.0000					
Roof Slope (ft/ft):							0.0000					
Shell Radius (ft):							5.0000					
Vapor Density												
Vapor Density (lb/cu ft):							0.0439					
Vapor Molecular Weight (lb/lb-mole):							69.4262					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.6915					
Daily Avg. Liquid Surface Temp. (deg. R):							544.5919					
Daily Average Ambient Temp. (deg. F):							85.3000					
Ideal Gas Constant R (psia cuft / (lb-mol-deg R)):							10.731					
Liquid Bulk Temperature (deg. R):							527.3183					
Tank Paint Solar Absorptance (Shell):							0.5400					
Tank Paint Solar Absorptance (Roof):							0.5400					
Daily Total Solar Insulation Factor (Btu/sqft day):							2,228.5045					
Vapor Space Expansion Factor												
Vapor Space Expansion Factor:							0.2645					
Daily Vapor Temperature Range (deg. R):							49.8230					
Daily Vapor Pressure Range (psia):							1.9195					
Breather Vent Press. Setting Range(psia):							0.0600					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.6915					
Vapor Pressure at Daily Minimum Liquid Surface Temperature (psia):							2.7967					
Vapor Pressure at Daily Maximum Liquid Surface Temperature (psia):							4.7163					
Daily Avg. Liquid Surface Temp. (deg R):							544.5919					
Daily Min. Liquid Surface Temp. (deg R):							532.1361					
Daily Max. Liquid Surface Temp. (deg R):							557.0476					
Daily Ambient Temp. Range (deg. R):							22.4000					
Vented Vapor Saturation Factor												
Vented Vapor Saturation Factor:							0.4053					
Vapor Pressure at Daily Average Liquid: Surface Temperature (psia):							3.6915					
Vapor Space Outage (ft):							7.5000					
Working Losses (lb):							216.1877					
Vapor Molecular Weight (lb/lb-mole):							69.4262					
Vapor Pressure at Daily Average Liquid Surface Temperature (psia):							3.6915					
Net Throughput (gal/mo.):							35,429.0000					
Annual Turnovers:							4.0169					
Turnover Factor:							1.0000					
Maximum Liquid Volume (gal):							8,820.0000					
Maximum Liquid Height (ft):							15.0000					
Tank Diameter (ft):							10.0000					
Working Loss Product Factor:							1.0000					
Total Losses (lb):							302.0190					

TANKS 4.0.9d
Emissions Report - Detail Format
Individual Tank Emission Totals

Emissions Report for: January, February, March, April, May, June, July, August, September, October, November, December

Condensate - Hourly Emissions - Vertical Fixed Roof Tank
Dallas-Fort Worth, Texas

	Losses(lbs)		
Components	Working Loss	Breathing Loss	Total Emissions
Condensate	216.19	85.83	302.02
Benzene	0.96	0.38	1.34
Butane	64.62	25.66	90.27
Decane (-n)	0.30	0.12	0.42
Ethane	1.00	0.40	1.40
Ethylbenzene	0.02	0.01	0.03
Heptane (-n)	26.53	10.53	37.06
Hexane (-n)	32.63	12.96	45.59
Nonane (-n)	1.19	0.47	1.66
Octane (-n)	7.14	2.84	9.98
Pentane (-n)	64.45	25.59	90.04
Propane	14.78	5.87	20.64
Toluene	2.13	0.85	2.98
Xylenes (mixed isomers)	0.42	0.17	0.59

APPENDIX C

Gas and Liquid Analyses

Inlet Gas Analysis

Component	Mole %
N2	1.0350
CO2	3.9520
H2S	0.0000
C1	77.7760
C2	9.8110
C3	4.5080
iC4	0.4910
nC4	1.2190
iC5	0.3280
nC5	0.3410
iC6	0.1800
NC6	0.1170
Benzene	0.0080
Cyclohexane	0.0250
IC7	0.1150
NC7	0.0310
Toluene	0.0080
IC8	0.0380
NC8	0.0050
E-Benzene	0.0000
m.o.p-Xylene	0.0020
IC9	0.0090
NC9	0.0010
IC10	0.0010
NC10	0.0000
I-Undecanes	0.0010
Total	100.00
Total TOC	95.02
Total VOC (NMNEHC)	7.43

file: EX0510A 200MM.xls
sheet: 200 MMscfd Ethane Recovery

11/23/2011

VALERUS

Valerus Compression Services

Houston, Texas

EXPANDER/COMPRESSOR

Client	**Targa**	P.O. Number	
Subject	**200 MMscfd Expander Plant**	By	DGH
Job No.	**26956 Ethane Recovery**	Revision	A

Tag No.	EC-0510		C-0510	
Service	EXPANDER		BOOSTER COMPRESSOR	
	Inlet	Outlet	Inlet	Outlet
Gas Composition, Mol %				
CO2	0.02%		0.01%	
N2	1.73%		1.75%	
H2S	0.00%		0.00%	
C1	87.62%		97.50%	
C2	7.86%		0.70%	
C3	2.28%		0.04%	
iC4	0.13%		0.00%	
nC4	0.28%		0.00%	
iC5	0.04%		0.00%	
nC5	0.03%		0.00%	
C6	0.01%		0.00%	
C7	0.00%		0.00%	
Flow Rate, Lbs/Hr	215,089		279,040	
Mols/Hr	11,804.46		17,051.02	
Mol Wt.	18.22		16.37	
Specific Heat, BTU/Lb-F	0.9635		0.5605	0.5758
Vapor Compressibility	0.6217	0.8139	0.9694	0.9706
k=Cp/Cv, Ideal	2.5080	1.6390	1.3380	1.3300
Flowrate, ACFM	606.50		6,411	5,520
Pressure, psia	930.0	285	265	329
Temperature, degF	-30.00	-113.10	115.0	154.4
Wt. % Liquid		16.46%		
Compression Ratio	3.26		1.24	
BHP	2310		2263	
RPM				
Efficiency, Design/Calc.%	83% / 87.0%		73% / 80.0%	
Lube Oil, gpm				
Lube Oil Pressure, psia				
Lube Oil Cooler, MBTU/Hr				
Seal Gas, SCFM	230 to 345			
Seal Gas Pressure, psia	470 to 915			
Seal Gas Temperature, degF	90 to 130 dF			
Connections, Size/Rating	8" 600#	10" 600#	18" 300#	16" 300#
Altitude, feet	950			
Ambient Temperature, degF	20 to 105 dF			
Manufacturer				
Model				

Notes:
1. Unit should be suitable for a Class 1, Group D, Div. 2 Area Classification per NEC Code.
2. Vendor to supply expander complete with lube oil system and seal gas system.
3. Vendor to include the required control panel suitable for the above operating area.

SHERRYLaboratories

Testing Today – Protecting Tomorrow®

CONDENSATE ANALYSIS REPORT NO.: 7-082106-7 (131847) **DATE:** 08/21/06

FOR: TARGA MIDSTREAM SERVICES
ATTN: ALBERT FLOURNOY
383 CR 1745
CHICO TX 76431

SAMPLE IDENTIFICATION:
COMPANY: TARGA MIDSTREAM SERVICES
FIELD: CHICO
LEASE: CHICO PLANT CONDENSATE
STA #:

SAMPLE DATA: **DATE:** 07/27/06 **BY:** R. N. WALTON
PSIG: 7 **TEMP:** 98 **DEG.F.**

REMARKS:

CYL #239

COMPONENT ANALYSIS

COMPONENT		MOL PERCENT	WT. PERCENT	LIQ VOL PERCENT
CARBON DIOXIDE	(CO2)	0.000	0.000	0.000
METHANE	(C1)	0.010	0.000	0.000
ETHANE	(C2)	0.137	0.040	0.080
PROPANE	(C3)	1.300	0.590	0.830
ISO-BUTANE	(IC4)	0.819	0.490	0.620
N-BUTANE	(NC4)	3.515	2.090	2.560
ISO-PENTANE	(IC5)	3.499	2.580	2.960
N-PENTANE	(NC5)	5.355	3.950	4.480
HEXANES	(C6)	12.894	11.350	12.240
HEPTANES PLUS	(C7+)	72.471	78.910	76.230
TOTALS		100.000	100.000	100.000

CALCULATED VALUES	TOTAL LIQ	HEPTANES PLUS
SPECIFIC GRAVITY @ 60 DEG. F. (WATER = 1)	0.7163	0.7416
MOLECULAR WEIGHT	97.90	106.60
POUNDS/GALLON (ABSOLUTE DENSITY)	5.9721	6.1829
POUNDS/GALLON (WEIGHT IN AIR)	5.9653	6.1760
CU. FT. VAPOR/GAL. @ 15.025 PSIA, 60 DEG F	22.643	21.529

2129 WEST WILLOW SCOTT LA 70583 337-232-3568

DATE: 08/21/06

SAMPLE IDENTIFICATION

COMPANY: TARGA MIDSTREAM SERVICES
FIELD: CHICO
LEASE: CHICO PLANT CONDENSATE
STA #:

SAMPLE DATE: 07/27/06
(131847)

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
METHANE	0.0000	0.0000	0.0000
ETHANE	0.0000	0.0000	0.0000
PROPANE	0.0000	0.0000	0.0000
ISO-BUTANE	0.0000	0.0000	0.0000
N-BUTANE	0.0000	0.0000	0.0000
2,2-DIMETHYLPROPANE (NEOPENTANE)	0.0000	0.0000	0.0000
ISOPENTANE	0.0000	0.0000	0.0000
N-PENTANE	0.0000	0.0000	0.0000
2,2-DIMETHYLBUTANE (NEOHEXANE)	0.0000	0.0000	0.0000
2,3-DIMETHYLBUTANE CYCLOPENTANE	0.0000	0.0000	0.0000
2-METHYLPENTANE	0.0000	0.0000	0.0000
3-METHYLPENTANE	0.0000	0.0000	0.0000
N-HEXANE	0.0000	0.0000	0.0000
2,2-DIMETHYLPENTANE	0.0000	0.0000	0.0000
METHYLCYCLOPENTANE	4.0787	3.5036	3.3313
2,4-DIMETHYLPENTANE	0.0000	0.0000	0.0000
2,2,3-TRIMETHYLBUTANE	0.0000	0.0000	0.0000
BENZENE	0.6334	0.5034	0.4078
3,3-DIMETHYLPENTANE	0.0000	0.0000	0.0000
CYCLOHEXANE	3.7779	3.2487	2.9707
2-METHYLHEXANE	3.7852	3.8705	4.0600
2,3-DIMETHYLPENTANE	0.0000	0.0000	0.0000
1,1-DIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
3-METHYLHEXANE	3.8547	3.9455	4.0875
1,t3-DIMETHYLCYCLOPENTANE	1.7458	1.7526	1.6664

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
1,c3-DIMETHYLCYCLOPENTANE 3-ETHYLPENTANE	3.4532	3.4697	3.3373
1,t2-DIMETHYLCYCLOPENTANE 2,2,4-TRIMETHYLPENTANE	0.0000	0.0000	0.0000
N-HEPTANE	8.1505	8.3386	8.6763
METHYLCYCLOHEXANE 1,1,3-TRIMETHYLCYCLOPENTANE 2,2-DIMETHYLHEXANE	7.5631	7.7000	7.1618
1,c2-DIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2,5-DIMETHYLHEXANE	1.9314	2.2568	2.3166
2,4-DIMETHYLHEXANE 2,2,3-TRIMETHYLPENTANE ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1,t2,c4-TRIMETHYLCYCLOPENTANE 3,3-DIMETHYLHEXANE	1.1436	1.3099	1.2517
1,t2,c3-TRIMETHYLCYCLOPENTANE	0.6254	0.7173	0.6777
2,3,4-TRIMETHYLPENTANE	0.0000	0.0000	0.0000
TOLUENE	3.8707	3.6425	2.9928
2,3-DIMETHYLHEXANE	0.0000	0.0000	0.0000
1,1,2-TRIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2-METHYLHEPTANE	2.7967	3.2645	3.3313
4-METHYLHEPTANE	0.0000	0.0000	0.0000
3,4-DIMETHYLHEXANE	0.0000	0.0000	0.0000
3-METHYLHEPTANE 3-ETHYLHEXANE	2.1473	2.5101	2.5278
1,c3-DIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOPENTANE 1,c2,t4-TRIMETHYLCYCLOPENTANE	3.6540	4.1885	3.8915
1,t4-DIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
2,2,5-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1,1-DIMETHYLCYCLOHEXANE 1,methyl-t3-ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1-methyl-c3-ETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
1-methyl-t2-ETHYLCYCLOPENTANE 2,2,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1-methyl-1-ETHYLCYCLOPENTANE CYCLOHEPTANE	0.0000	0.0000	0.0000

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
N-OCTANE 1,t2-DIMETHYLCYCLOHEXANE	5.9948	6.9962	7.0902
UNKNOWN	0.0000	0.0000	0.0000
1,t3-DIMETHYLCYCLOHEXANE 1,c4-DIMETHYLCYCLOHEXANE 1,c2,c3-TRIMETHYLCYCLOPENTANE	0.0000	0.0000	0.0000
2,4,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
ISOPROPYLCYCLOPENTANE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0016	0.0015
2,2-DIMETHYLHEPTANE	0.0000	0.0000	0.0000
2,4-DIMETHYLHEPTANE 1-methyl-c2-ETHYLCYCLOPENTANE	0.0312	0.0426	0.0404
2,2,3-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
1,c2-DIMETHYLCYCLOHEXANE 2,6-DIMETHYLHEPTANE	0.3087	0.3654	0.3339
N-PROPYLCYCLOPENTANE 1,c3,c5-TRIMETHYLCYCLOHEXANE	0.5638	0.6841	0.6304
2,5-DIMETHYLHEPTANE 3,5-DIMETHYLHEPTANE ETHYLCYCLOHEXANE	0.2855	0.3362	0.3072
1,1,3-TRIMETHYLCYCLOHEXANE 2,3,3-TRIMETHYLHEXANE 3,3-DIMETHYLHEPTANE	0.5022	0.6510	0.6144
1,1,4-TRIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0000	0.0000
2,3,4-TRIMETHYLHEXANE	0.0000	0.0000	0.0000
ETHYLBENZENE	0.0848	0.0931	0.0762
1,t2,t4-TRIMETHYLCYCLOHEXANE	0.0000	0.0032	0.0030
1,c3,t5-TRIMETHYLCYCLOHEXANE 2,3-DIMETHYLHEPTANE	0.0000	0.0000	0.0000
M-XYLENE P-XYLENE 3,4-DIMETHYLHEPTANE	1.6531	1.7991	1.4911
2-METHYLOCTANE 4-METHYLOCTANE	1.1972	1.5735	1.5650
UNKNOWN	0.0000	0.0000	0.0000
3-METHYLOCTANE	1.1436	1.4977	1.4811

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.0000	0.0000	0.0000
1,t2,c3-TRIMETHYLCYCLOHEXANE 1,t2,c4-TRIMETHYLCYCLOHEXANE	0.0000	0.0000	0.0000
O-XYLENE	0.5638	0.6100	0.4940
1,1,2-TRIMETHYLCYCLOHEXANE	0.0928	0.1215	0.1082
UNKNOWN	0.3247	0.4719	0.4543
ISOBUTYLCYCLOPENTANE	0.0000	0.0000	0.0000
N-NONANE	2.6032	3.4121	3.3869
UNKNOWN	0.0000	0.0000	0.0000
1,c2,c3-TRIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOHEXANE	0.0080	0.0126	0.0114
UNKNOWN	0.0000	0.0000	0.0000
ISOPROPYLBENZENE	0.0000	0.0008	0.0008
2,2-DIMETHYLOCTANE	0.0152	0.0229	0.0229
ISOPROPYLCYCLOHEXANE CYCLOOCTANE	0.0384	0.0434	0.0374
UNKNOWN	0.0384	0.0552	0.0503
N-BUTYLCYCLOPENTANE N-PROPYLCYCLOHEXANE	0.3711	0.4758	0.4299
3,3-DIMETHYLOCTANE	0.0000	0.0000	0.0000
UNKNOWN	0.0464	0.0631	0.0572
N-PROPYLBENZENE	0.0544	0.0655	0.0541
UNKNOWN	0.0000	0.0000	0.0000
m-ETHYLTOLUENE	0.1855	0.2304	0.1898
p-ETHYLTOLUENE 2,3-DIMETHYLOCTANE	0.2623	0.3235	0.2676
4-METHYLNONANE 5-METHYLNONANE 1,3,5-TRIMETHYLBENZENE	0.2239	0.2975	0.2615
2-METHYLNONANE	0.0000	0.0000	0.0000
3-ETHYLOCTANE	0.0000	0.0000	0.0000
O-ETHYLTOLUENE 3-METHYLNONANE	0.1239	0.1633	0.1441
UNKNOWN	0.0312	0.0442	0.0404
1,2,4-TRIMETHYLBENZENE t-BUTYLBENZENE METHYLCYCLOOCTANE	0.2855	0.3677	0.3034

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
tert-BUTYLCYCLOHEXANE	0.0000	0.0000	0.0000
ISO-BUTYLCYCLOHEXANE	0.0000	0.0000	0.0000
N-DECANE	0.4095	0.5958	0.5816
ISOBUTYLBENZENE	0.0000	0.0000	0.0000
sec-BUTYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0000	0.0000	0.0000
1-METHYL-3-ISOPROPYLBENZENE	0.1080	0.1468	0.1220
1,2,3-TRIMETHYLBENZENE 1-METHYL-4-ISOPROPYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0928	0.1491	0.1441
1-METHYL-2-ISOPROPYLBENZENE	0.0312	0.0442	0.0358
UNKNOWN	0.0384	0.0671	0.0648
N-BUTYLCYCLOHEXANE	0.0232	0.0379	0.0343
UNKNOWN	0.0000	0.0000	0.0000
1,3-DIETHYLBENZENE 1-METHYL-3-PROPYLBENZENE	0.0232	0.0276	0.0229
1,2-DIETHYLBENZENE N-BUTYLBENZENE 1-METHYL-4-PROPYLBENZENE	0.0464	0.0584	0.0480
1,4-DIETHYLBENZENE	0.0616	0.0876	0.0724
1-METHYL-2-PROPYLBENZENE	0.0312	0.0473	0.0389
1,4-DIMETHYL-2-ETHYLBENZENE	0.0080	0.0087	0.0069
UNKNOWN	0.0152	0.0237	0.0229
1,2-DIMETHYL-4-ETHYLBENZENE	0.0080	0.0079	0.0069
1,3-DIMETHYL-2-ETHYLBENZENE	0.0000	0.0000	0.0000
UNKNOWN	0.0464	0.0789	0.0762
1,2-DIMETHYL-3-ETHYLBENZENE	0.0464	0.0655	0.0526
UNKNOWN	0.0000	0.0000	0.0000
N-UNDECANE	0.2087	0.3362	0.3240
UNKNOWN	0.0544	0.0931	0.0884
1,2,4,5-TETRAMETHYLBENZENE	0.0152	0.0166	0.0130
1,2,3,5-TETRAMETHYLBENZENE	0.0000	0.0008	0.0008
UNKNOWN	0.0152	0.0276	0.0267
1,2,3,4-TETRAMETHYLBENZENE CYCLODECANE	0.0080	0.0126	0.0107

CAPILLARY ANALYSIS
COMPONENTS AS % OF TOTAL SAMPLE

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.1007	0.1768	0.1685
NAPHTHALENE	0.0000	0.0047	0.0030
N-DODECANE	0.1623	0.2864	0.2721
ISOTRIDECANES PLUS	0.6718	1.4614	1.3554
TOTALS	72.4710	78.9100	76.2300

TOTAL HEXANES	=	0.0000	0.0000	0.0000
TOTAL HEPTANES	=	29.4794	28.6326	28.5373
TOTAL OCTANES	=	29.7270	32.5858	31.2414
TOTAL NONANES	=	9.3546	11.6630	10.9876
TOTAL DECANES PLUS	=	3.9100	6.0286	5.4637

DATE: 08/21/06

SAMPLE IDENTIFICATION

COMPANY: TARGA MIDSTREAM SERVICES
FIELD: CHICO
LEASE: CHICO PLANT CONDENSATE
STA #:

SAMPLE DATE: 07/27/06
(131847)

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
METHANE	0.000	0.000	0.000
ETHANE	0.000	0.000	0.000
PROPANE	0.000	0.000	0.000
ISO-BUTANE	0.000	0.000	0.000
N-BUTANE	0.000	0.000	0.000
2,2-DIMETHYLPROPANE (NEOPENTANE)	0.000	0.000	0.000
ISOPENTANE	0.000	0.000	0.000
N-PENTANE	0.000	0.000	0.000
2,2-DIMETHYLBUTANE (NEOHEXANE)	0.000	0.000	0.000
2,3-DIMETHYLBUTANE CYCLOPENTANE	0.000	0.000	0.000
2-METHYLPENTANE	0.000	0.000	0.000
3-METHYLPENTANE	0.000	0.000	0.000
N-HEXANE	0.000	0.000	0.000
2,2-DIMETHYLPENTANE	0.000	0.000	0.000
METHYLCYCLOPENTANE	5.628	4.440	4.370
2,4-DIMETHYLPENTANE	0.000	0.000	0.000
2,2,3-TRIMETHYLBUTANE	0.000	0.000	0.000
BENZENE	0.874	0.638	0.535
3,3-DIMETHYLPENTANE	0.000	0.000	0.000
CYCLOHEXANE	5.213	4.117	3.897
2-METHYLHEXANE	5.223	4.905	5.326
2,3-DIMETHYLPENTANE	0.000	0.000	0.000
1,1-DIMETHYLCYCLOPENTANE	0.000	0.000	0.000
3-METHYLHEXANE	5.319	5.000	5.362
1,t3-DIMETHYLCYCLOPENTANE	2.409	2.221	2.186

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
1,c3-DIMETHYLCYCLOPENTANE 3-ETHYLPENTANE	4.765	4.397	4.378
1,t2-DIMETHYLCYCLOPENTANE 2,2,4-TRIMETHYLPENTANE	0.000	0.000	0.000
N-HEPTANE	11.247	10.567	11.382
METHYLCYCLOHEXANE 1,1,3-TRIMETHYLCYCLOPENTANE 2,2-DIMETHYLHEXANE	10.436	9.758	9.395
1,c2-DIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2,5-DIMETHYLHEXANE	2.665	2.860	3.039
2,4-DIMETHYLHEXANE 2,2,3-TRIMETHYLPENTANE ETHYLCYCLOPENTANE	0.000	0.000	0.000
1,t2,c4-TRIMETHYLCYCLOPENTANE 3,3-DIMETHYLHEXANE	1.578	1.660	1.642
1,t2,c3-TRIMETHYLCYCLOPENTANE	0.863	0.909	0.889
2,3,4-TRIMETHYLPENTANE	0.000	0.000	0.000
TOLUENE	5.341	4.616	3.926
2,3-DIMETHYLHEXANE	0.000	0.000	0.000
1,1,2-TRIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2-METHYLHEPTANE	3.859	4.137	4.370
4-METHYLHEPTANE	0.000	0.000	0.000
3,4-DIMETHYLHEXANE	0.000	0.000	0.000
3-METHYLHEPTANE 3-ETHYLHEXANE	2.963	3.181	3.316
1,c3-DIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOPENTANE 1,c2,t4-TRIMETHYLCYCLOPENTANE	5.042	5.308	5.105
1,t4-DIMETHYLCYCLOHEXANE	0.000	0.000	0.000
2,2,5-TRIMETHYLHEXANE	0.000	0.000	0.000
1,1-DIMETHYLCYCLOHEXANE 1,methyl-t3-ETHYLCYCLOPENTANE	0.000	0.000	0.000
1-methyl-c3-ETHYLCYCLOPENTANE	0.000	0.000	0.000
1-methyl-t2-ETHYLCYCLOPENTANE 2,2,4-TRIMETHYLHEXANE	0.000	0.000	0.000
1-methyl-1-ETHYLCYCLOPENTANE CYCLOHEPTANE	0.000	0.000	0.000

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
N-OCTANE 1,t2-DIMETHYLCYCLOHEXANE	8.272	8.866	9.301
UNKNOWN	0.000	0.000	0.000
1,t3-DIMETHYLCYCLOHEXANE 1,c4-DIMETHYLCYCLOHEXANE 1,c2,c3-TRIMETHYLCYCLOPENTANE	0.000	0.000	0.000
2,4,4-TRIMETHYLHEXANE	0.000	0.000	0.000
ISOPROPYLCYCLOPENTANE	0.000	0.000	0.000
UNKNOWN	0.000	0.002	0.002
2,2-DIMETHYLHEPTANE	0.000	0.000	0.000
2,4-DIMETHYLHEPTANE 1-methyl-c2-ETHYLCYCLOPENTANE	0.043	0.054	0.053
2,2,3-TRIMETHYLHEXANE	0.000	0.000	0.000
1,c2-DIMETHYLCYCLOHEXANE 2,6-DIMETHYLHEPTANE	0.426	0.463	0.438
N-PROPYLCYCLOPENTANE 1,c3,c5-TRIMETHYLCYCLOHEXANE	0.778	0.867	0.827
2,5-DIMETHYLHEPTANE 3,5-DIMETHYLHEPTANE ETHYLCYCLOHEXANE	0.394	0.426	0.403
1,1,3-TRIMETHYLCYCLOHEXANE 2,3,3-TRIMETHYLHEXANE 3,3-DIMETHYLHEPTANE	0.693	0.825	0.806
1,1,4-TRIMETHYLCYCLOHEXANE	0.000	0.000	0.000
UNKNOWN	0.000	0.000	0.000
2,3,4-TRIMETHYLHEXANE	0.000	0.000	0.000
ETHYLBENZENE	0.117	0.118	0.100
1,t2,t4-TRIMETHYLCYCLOHEXANE	0.000	0.004	0.004
1,c3,t5-TRIMETHYLCYCLOHEXANE 2,3-DIMETHYLHEPTANE	0.000	0.000	0.000
M-XYLENE P-XYLENE 3,4-DIMETHYLHEPTANE	2.281	2.280	1.956
2-METHYLOCTANE 4-METHYLOCTANE	1.652	1.994	2.053
UNKNOWN	0.000	0.000	0.000
3-METHYLOCTANE	1.578	1.898	1.943

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.000	0.000	0.000
1,t2,c3-TRIMETHYLCYCLOHEXANE 1,t2,c4-TRIMETHYLCYCLOHEXANE	0.000	0.000	0.000
O-XYLENE	0.778	0.773	0.648
1,1,2-TRIMETHYLCYCLOHEXANE	0.128	0.154	0.142
UNKNOWN	0.448	0.598	0.596
ISOBUTYLCYCLOPENTANE	0.000	0.000	0.000
N-NONANE	3.592	4.324	4.443
UNKNOWN	0.000	0.000	0.000
1,c2,c3-TRIMETHYLCYCLOHEXANE 1,c2,t3-TRIMETHYLCYCLOHEXANE	0.011	0.016	0.015
UNKNOWN	0.000	0.000	0.000
ISOPROPYLBENZENE	0.000	0.001	0.001
2,2-DIMETHYLOCTANE	0.021	0.029	0.030
ISOPROPYLCYCLOHEXANE CYCLOOCTANE	0.053	0.055	0.049
UNKNOWN	0.053	0.070	0.066
N-BUTYLCYCLOPENTANE N-PROPYLCYCLOHEXANE	0.512	0.603	0.564
3,3-DIMETHYLOCTANE	0.000	0.000	0.000
UNKNOWN	0.064	0.080	0.075
N-PROPYLBENZENE	0.075	0.083	0.071
UNKNOWN	0.000	0.000	0.000
m-ETHYLTOLUENE	0.256	0.292	0.249
p-ETHYLTOLUENE 2,3-DIMETHYLOCTANE	0.362	0.410	0.351
4-METHYLNONANE 5-METHYLNONANE 1,3,5-TRIMETHYLBENZENE	0.309	0.377	0.343
2-METHYLNONANE	0.000	0.000	0.000
3-ETHYLOCTANE	0.000	0.000	0.000
O-ETHYLTOLUENE 3-METHYLNONANE	0.171	0.207	0.189
UNKNOWN	0.043	0.056	0.053
1,2,4-TRIMETHYLBENZENE t-BUTYLBENZENE METHYLCYCLOOCTANE	0.394	0.466	0.398

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
tert-BUTYLCYCLOHEXANE	0.000	0.000	0.000
ISO-BUTYLCYCLOHEXANE	0.000	0.000	0.000
N-DECANE	0.565	0.755	0.763
ISOBUTYLBENZENE	0.000	0.000	0.000
sec-BUTYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.000	0.000	0.000
1-METHYL-3-ISOPROPYLBENZENE	0.149	0.186	0.160
1,2,3-TRIMETHYLBENZENE 1-METHYL-4-ISOPROPYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.128	0.189	0.189
1-METHYL-2-ISOPROPYLBENZENE	0.043	0.056	0.047
UNKNOWN	0.053	0.085	0.085
N-BUTYLCYCLOHEXANE	0.032	0.048	0.045
UNKNOWN	0.000	0.000	0.000
1,3-DIETHYLBENZENE 1-METHYL-3-PROPYLBENZENE	0.032	0.035	0.030
1,2-DIETHYLBENZENE N-BUTYLBENZENE 1-METHYL-4-PROPYLBENZENE	0.064	0.074	0.063
1,4-DIETHYLBENZENE	0.085	0.111	0.095
1-METHYL-2-PROPYLBENZENE	0.043	0.060	0.051
1,4-DIMETHYL-2-ETHYLBENZENE	0.011	0.011	0.009
UNKNOWN	0.021	0.030	0.030
1,2-DIMETHYL-4-ETHYLBENZENE	0.011	0.010	0.009
1,3-DIMETHYL-2-ETHYLBENZENE	0.000	0.000	0.000
UNKNOWN	0.064	0.100	0.100
1,2-DIMETHYL-3-ETHYLBENZENE	0.064	0.083	0.069
UNKNOWN	0.000	0.000	0.000
N-UNDECANE	0.288	0.426	0.425
UNKNOWN	0.075	0.118	0.116
1,2,4,5-TETRAMETHYLBENZENE	0.021	0.021	0.017
1,2,3,5-TETRAMETHYLBENZENE	0.000	0.001	0.001
UNKNOWN	0.021	0.035	0.035
1,2,3,4-TETRAMETHYLBENZENE CYCLODECANE	0.011	0.016	0.014

CAPILLARY ANALYSIS
HEAVY END FRACTION

COMPONENT	MOL PERCENT	WT. PERCENT	LIQ. VOL. PERCENT
UNKNOWN	0.139	0.224	0.221
NAPHTHALENE	0.000	0.006	0.004
N-DODECANE	0.224	0.363	0.357
ISOTRIDECANES PLUS	0.927	1.852	1.778
TOTALS	100.000	100.000	100.000

SPECIFIC GRAVITY @ 60 DEG. F. (WATER = 1)	0.7416
MOLECULAR WEIGHT	106.60
POUNDS/GALLON (ABSOLUTE DENSITY)	6.1829
POUNDS/GALLON (WEIGHT IN AIR)	6.1760
CU. FT. VAPOR/GAL @ 14.696 PSIA & 60 DEG. F.	22.011
CU. FT. VAPOR/GAL @ 15.025 PSIA & 60 DEG. F.	21.529
BTU/CU.FT. @ 14.696 PSIA, DRY	5706.8
BTU/CU.FT. @ 15.025 PSIA, DRY	5834.6
BTU/GALLON	125612
BTU/POUND	20316
SPECIFIC GRAVITY AS VAPOR	3.6811
COMPRESSIBILITY FACTOR	0.8084
SUMMATION FACTOR	0.1142

APPENDIX D

RBLC Search Results

Heaters <10 MMBtu - NOx

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	NUCOR YAMATO STEEL	MISSISSIPPI	AR	NATURAL GAS			NOx	LOW NOX BURNERS	0.098	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	PALM BEACH COUNTY	FL	NATURAL GAS	10	MMBTU/H	NOx	GOOD COMBUSTION	0.095	LB/MMBTU
IA-0058	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	POLK	IA	NATURAL GAS			NOx		0.041	LB/MMBTU
MI-0390	WHITE PIGEON COMPRESSOR STATION - PLANT #3	CONSUMERS ENERGY	ST. JOSEPH	MI	NATURAL GAS	0		NOx		0.025	LB/MMBTU
MO-0067	SOUTH HARPER PEAKING FACILITY	AQUILA, INC.	CASS	MO	NATURAL GAS	9.8	mmBtu/h	NOx	LOW NOX BURNERS		
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	NOx	BEST COMBUSTION PRACTICES	0.14	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	NOx	BEST COMBUSTION PRACTICES	0.14	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	9.1	MMBTU/H	NOx		0.14	LB/MMBTU
TX-0346	WEST REFINERY	FLINT HILLS RESOURCES LP	NUECES	TX				NOx	NONE INDICATED	0.08	LB/MMBTU
TX-0346	WEST REFINERY	FLINT HILLS RESOURCES LP	NUECES	TX				NOx	NONE INDICATED	0.1	LB/MMBTU

Heaters <10 MMBtu - CO

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	NUCOR YAMATO STEEL	MISSISSIPPI	AR	NATURAL GAS			CO	GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	PALM BEACH COUNTY	FL	NATURAL GAS	10	MMBTU/H	CO	GOOD COMBUSTION	0.08	LB/MMBTU
IA-0058	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	POLK	IA	NATURAL GAS			CO		0.032	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	CO	BEST COMBUSTION PRACTICES	0.03	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	CO	BEST COMBUSTION PRACTICES	0.03	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	9.1	MMBTU/H	CO		0.035	LB/MMBTU

Heaters between 10 and 100 MMBtu - NOx

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	NUCOR YAMATO STEEL	MISSISSIPPI	AR	NATURAL GAS			Nitrogen (	LOW NOX BURNERS	0.098	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	PALM BEACH COUNTY	FL	NATURAL GAS	10	MMBTU/H	Nitrogen (	GOOD COMBUSTION	0.095	LB/MMBTU
IA-0058	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	POLK	IA	NATURAL GAS			Nitrogen Oxides (NOx)		0.041	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	42.2	MMBTU/H	Nitrogen Oxides (NOx)		0.073	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	50	MMBTU/H	Nitrogen Oxides (NOx)		0.03	LB/MMBTU
TX-0346	WEST REFINERY	FLINT HILLS RESOURCES LP	NUECES	TX				Nitrogen (	NONE INDICATED	0.08	LB/MMBTU
TX-0346	WEST REFINERY	FLINT HILLS RESOURCES LP	NUECES	TX				Nitrogen (	NONE INDICATED	0.1	LB/MMBTU
TX-0359	LIMESTONE ELECTRIC GENERATING STATION	RELIANT ENERGY INC	LIMESTONE	TX	NAT GAS			Nitrogen (	NONE INDICATED	0.045	LB/MMBTU
WI-0212	SENA - NIAGARA MILL	STORA ENSO NORTH AMERICA	MARINETTE	WI	NATURAL GAS	35.3	MMBTU/H	Nitrogen (	LOW-NOX BURNERS	0.044	LB/MMBTU

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
CA-1001	CENCO REFINING COMPANY	CENCO REFINING COMPANY	LOS ANGELES	CA	NATURAL GAS	50	MMBTU/H	Nitrogen (	SCR WITH AMMONIA INJECTION-TECHNIP USA	5	PPMVD @ 3% O2
CA-1028	CENCO REFINING COMPANY	CENCO REFINING COMPANY		CA	NATURAL GAS	50	MMBTU/H	Nitrogen (	LOW NOX BURNER- SCR WITH NH3	5	PPMVD @ 3% O2

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
MT-0030	BILLINGS REFINERY	CONOCOPHILLIPS COMPANY	YELLOWSTONE	MT	NATURAL GAS	58	MMBTU/H	Nitrogen (	NEXT GENERATION ULNB WITH AIR PREHEATER	0.039	LB/MMBTU

Heaters between 10 and 100 MMBtu - CO

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
AR-0055	NUCOR YAMATO STEEL (ARMOREL)	NUCOR YAMATO STEEL	MISSISSIPPI	AR	NATURAL GAS			Carbon M	GOOD COMBUSTION PRACTICE	0.0824	LB/MMBTU
FL-0303	FPL WEST COUNTY ENERGY CENTER UNIT 3	FLORIDA POWER AND LIGHT COMPANY (FP&L)	PALM BEACH COUNTY	FL	NATURAL GAS	10	MMBTU/H	Carbon M	GOOD COMBUSTION	0.08	LB/MMBTU
IA-0058	GREATER DES MOINES ENERGY CENTER	MIDAMERICAN ENERGY	POLK	IA	NATURAL GAS			Carbon Monoxide		0.032	LB/MMBTU
IA-0060	HAWKEYE GENERATING, LLC	ENTERGY	ADAIR	IA	NATUAL GAS	6.5	MMBTU/H	Carbon M	GCP	0.033	LB/MMBTU
IA-0060	HAWKEYE GENERATING, LLC	ENTERGY	ADAIR	IA	NATURAL GAS	6.5	MMBTU/H	Carbon M	GCP	0.033	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	Carbon M	BEST COMBUSTION PRACTICES	0.03	LB/MMBTU
NV-0035	TRACY SUBSTATION EXPANSION PROJECT	SIERRA PACIFIC POWER COMPANY	STOREY COUNTY	NV	NATURAL GAS	4	MMBTU/H	Carbon M	BEST COMBUSTION PRACTICES	0.03	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	42.2	MMBTU/H	Carbon Monoxide		0.01	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	9.1	MMBTU/H	Carbon Monoxide		0.035	LB/MMBTU
TN-0153	WILLIAMS REFINING & MARKETING, L.L.C.	WILLIAMS REFINING & MARKETING, L.L.C.	SHELBY	TN	NATURAL GAS	50	MMBTU/H	Carbon Monoxide		0.07	LB/MMBTU
WI-0212	SENA - NIAGARA MILL	STORA ENSO NORTH AMERICA	MARINETTE	WI	NATURAL GAS	35.3	MMBTU/H	Carbon M	GOOD COMBUSTION	0.06	LB/MMBTU

RBLCID	FACILITY_NAME	CORPORATE_OR_COMPANY_NAME	FACILITY_COUNTY	FACILITY_STATE	PRIMARY_FUEL	THROUGHPUT	THROUGHPUT_UNIT	POLLUTANT	CONTROL_METHOD_DESCRIPTION	EMISSION_LIMIT_1	EMISSION_LIMIT_1_UNIT
CA-1001	CENCO REFINING COMPANY	CENCO REFINING COMPANY	LOS ANGELES	CA	NATURAL GAS	50	MMBTU/H	Carbon Monoxide		10	PPMVD @ 3% O2
CA-1028	CENCO REFINING COMPANY	CENCO REFINING COMPANY		CA	NATURAL GAS	50	MMBTU/H	Carbon Monoxide		10	PPMVD @ 3% O2

APPENDIX E

BACT Cost Analysis

Supplemental Gas to Flare to Control Amine Treater and TEG Dehydrator During RTO Maintenance

Flare Parameters

Supplemental Fuel Rate =	216,182.99	scf/hr
Scheduled RTO maintenance duration =	38	hr/event
Scheduled RTO maintenance frequency =	4	events/yr
Hours of Operation =	152	hr/yr
Flare Destruction Rate Efficiency (DRE) =	98%	%

Uncontrolled Annual Emissions

Pollutant	Amine Emissions (tpy)	Dehy Emissions (tpy)	Total Emissions (tpy)
VOC	1.41	4.15	5.56

Flare Annual Emissions Comparison

Estimated Cost per 1,000 scf ($/1,000 scf)	Estimated Cost per Year ($/yr)	Controlled VOC Annual Emissions (tpy)	Cost for Reduction in VOC Emissions ($/ton-yr)
4.00	$131,439.26	0.11	$24,107.56

[1] Cost per Mscf provided via email from Melanie Roberts, Targa, to Jessica Coleman, Trinity, on January 16, 2012.

APPENDIX F

Equipment Tables

TABLE 4

COMBUSTION UNITS

OPERATIONAL DATA	
Number from flow diagram: EPN 5	Model Number(if available):
Name of device: Regenerative Thermal Oxidizer	Manufacturer

CHARACTERISTICS OF INPUT

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Waste Material*	1. See attached emission calculations for details			
	2.			
	3.			
	4.			
	5.			

Gross Heating Value of Waste Material (Wet basis if applicable)	Btu/lb	Air Supplied for Waste Material	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)
	______		________	__________

Waste Material of Contaminated Gas	Total Flow Rate lb/hr		Inlet Temperature °F	
	Minimum Expected	Design Maximum	Minimum Expected	Design Maximum
	________	27,683	__________	_________

	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
Fuel	1. No supplemental fuel during normal operation			
	2.			
	3.			
	4.			

Gross Heating Value of Fuel	Btu/lb	Air Supplied for Fuel	Minimum SCFM (70°F & 14.7 psia)	Maximum SCFM(70°F & 14.7 psia)
	___		________	________

*Describe how waste material is introduced into combustion unit on an attached sheet. Supply drawings, dimensioned and to scale to show clearly the design and operation of the unit.

TABLE 4
(continued)

COMBUSTION UNITS

CHARACTERISTICS OF OUTPUT				
Flue Gas Released	Chemical Composition			
	Material	Min. Value Expected lb/hr	Ave. Value Expected lb/hr	Design Maximum lb/hr
	1. See attached emission calculations for details			
	2.			
	3.			
	4.			
	5.			
Temperature at Stack Exit °F	Total Flow Rate lb/hr		Velocity at Stack Exit ft/sec	
600	Minimum Expected	Maximum Expected	Minimum Expected	Maximum Expected 51.97

COMBUSTION UNIT CHARACTERISTICS		
Chamber Volume from Drawing ft³	Chamber Velocity at Average Chamber Temperature ft/sec	Average Chamber Temperature °F
Average Residence Time sec	Exhaust Stack Height ft 30.00	Exhaust Stack Diameter ft 3.50

ADDITIONAL INFORMATION FOR CATALYTIC COMBUSTION UNITS		
Number and Type of Catalyst Elements	Catalyst Bed Velocity ft/sec	Max. Flow Rate per Catalytic Unit (Manufacturer's Specifications) Specify Units

Attach separate sheets as necessary providing a description of the combustion unit, including details regarding principle of operation and the basis for calculating its efficiency. Supply an assembly drawing, dimensioned and to scale, to show clearly the design and operation of the equipment. If the device has bypasses, safety valves, etc., specify when such bypasses are to be used and under what conditions. Submit explanations on control for temperature, air flow rates, fuel rates, and other operating variables.

TABLE 6

BOILERS AND HEATERS

Type of Device: TEG Reboiler			Manufacturer:	
Number from flow diagram: EPN 1			Model Number:	
CHARACTERISTICS OF INPUT				
Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
Natural Gas	See attached emission calculations for Residue Gas composition		Average	Design Maximum 17,420 scf/hr
		Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM						
Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS			
Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS					
Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp°F	scfm
16 in	16.67 ft		3.47 fps	750 deg	665 acfm

CHARACTERISTICS OF OUTPUT	
Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations
Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.	

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: HTR-1 Regen Heater	Manufacturer:
Number from flow diagram: EPN 3	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average	Design Maximum 52,800 scf/hr
Natural Gas	See attached emission calculations for Residue Gas composition	Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average _____ scfm* ___% excess (vol)	Design Maximum _______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
2.5 ft	18 ft		6.45 fps	680 deg F	1,900 acfm

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 6

BOILERS AND HEATERS

Type of Device: Hot Oil Heater	Manufacturer:
Number from flow diagram: EPN 4	Model Number:

CHARACTERISTICS OF INPUT

Type Fuel	Chemical Composition (% by Weight)	Inlet Air Temp °F (after preheat)	Fuel Flow Rate (scfm* or lb/hr)	
			Average	Design Maximum 935,196 scf/hr
Natural Gas	See attached emission calculations for Residue Gas composition	Gross Heating Value of Fuel	Total Air Supplied and Excess Air	
		(specify units) 1,000 Btu/scf	Average ____ scfm* ___% excess (vol)	Design Maximum ______ scfm * ______% excess (vol)

HEAT TRANSFER MEDIUM

Type Transfer Medium	Temperature °F		Pressure (psia)		Flow Rate (specify units)	
(Water, oil, etc.)	Input	Output	Input	Output	Average	Design Maxim

OPERATING CHARACTERISTICS

Ave. Fire Box Temp. at max. firing rate	Fire Box Volume(ft.^{3}), (from drawing)	Gas Velocity in Fire Box (ft/sec) at max firing rate	Residence Time in Fire Box at max firing rate (sec)

STACK PARAMETERS

Stack Diameters	Stack Height	Stack Gas Velocity (ft/sec)		Stack Gas	Exhaust
		(@Ave.Fuel Flow Rate)	(@Max. Fuel Flow Rate)	Temp °F	scfm
6.75 in	124 ft		13.89 fps	550 deg F	29,815 acfm

CHARACTERISTICS OF OUTPUT

Material	Chemical Composition of Exit Gas Released (% by Volume)
	See attached emission calculations

Attach an explanation on how temperature, air flow rate, excess air or other operating variables are controlled.

Also supply an assembly drawing, dimensioned and to scale, in plan, elevation, and as many sections as are needed to show clearly the operation of the combustion unit.Show interior dimensions and features of the equipment necessary to calculate in performance.

*Standard Conditions: 70°F,14.7 psia

TABLE 7(b)

02-95

HORIZONTAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,085 m E, 3,686,958 m N
3. Tank No. 11 4. Emission Point No. EPN 11
5. FIN FIN 11 CIN ____
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Length : 10.75 ft.
   b. Diameter: 4 ft.
   c. Nominal Capacity or Working Volume: 1,000 gallons.
   d. Turnovers per year: 52.0
   e. Net Throughput : 52,000 gallons/year.
   f. Maximum Filling Rate: 1,000 gallons/hour.
   g. Is the tank underground? Yes [ ] No [X]
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   b. Shell Condition : Good [X] Poor [ ]

3. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	atmosphere
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Permit No. ______________________ Tank No. EPN 11

III. *Liquid Properties of Stored Material*

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [X] *Complete Section III.3*

   Multiple [ ] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: Methyl Alcohol
   b. CAS Number: 67-56-1
   c. Average Liquid Surface Temperature: 73.27 °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: 2.220 psia.
   e. Liquid Molecular Weight: 32.04
4. Multiple Component Information
   a. Mixture Name: ______________________
   b. Average Liquid Surface Temperature: _________ °F.
   c. Minimum Liquid Surface Temperature: _________ °F.
   d. Maximum Liquid Surface Temperature: _________ °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: __________ psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: __________ psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: _________ psia.
   h. Liquid Molecular Weight: ____________
   i. Vapor Molecular Weight: ____________

j. Chemical Components Information

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank).*

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,360 m E, 3,686,790 m N
3. Tank No. 16 4. Emission Point No. EPN 16
5. FIN FIN 16 CIN ____
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ____ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	atmosphere
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. EPN 16

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Produced water
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** (*Use a separate form for each tank*).

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,363 m E, 3,686,793 m N
3. Tank No. 17 4. Emission Point No. EPN 17
5. FIN FIN 17 CIN VRU
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ____________

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ____________)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ____________ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	VRU; atmosphere during VRU downtime
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. EPN 17

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid
   Single [ ] *Complete Section III.3*
   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ______________________________
   b. CAS Number: ________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ___________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 7(a)

02-95

VERTICAL FIXED ROOF STORAGE TANK SUMMARY

I. ***Tank Identification*** *(Use a separate form for each tank)*.

1. Applicant's Name: Targa Gas Processing LLC
2. Location (*indicate on plot plan and provide coordinates*): 637,363 m E, 3,686,793 m N
3. Tank No. 18   4. Emission Point No. EPN 18
5. FIN FIN 18   CIN VRU
6. Status: New tank [X] Altered tank [ ] Relocation [ ] Change of Service [ ]

Previous permit or exemption number(s) ______

II. ***Tank Physical Characteristics***

1. Dimensions
   a. Shell Height : 15 ft.
   b. Diameter: 10 ft.
   c. Maximum Liquid Height : 15 ft.
   d. Nominal Capacity or Working Volume: 8,820 gallons.
   e. Turnovers per year: 47.17
   f. Net Throughput : 416,000 gallons/year.
   g. Maximum Filling Rate: 8,000 gallons/hour.
2. Paint Characteristics
   a. Shell Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   b. Shell Condition : Good [X] Poor [ ]
   c. Roof Color/Shade : White/White [ ] Aluminum/Specular [ ] Aluminum/Diffuse [ ] Gray/Light [X] Gray/Medium [ ] Red/Primer [ ] Other [ ] (Describe ______)
   d. Roof Condition : Good [X] Poor [ ]
3. Roof Characteristics
   a. Roof Type: Dome [ ] Cone [X]
   b. Roof Height: 0.00 ft. (*not including shell height)*
   c. Radius (*Dome Roof Only*): ______ ft.
   d. Slope (*Cone Roof Only*): 0.00 ft/ft.

4. Breather Vent Settings				SPECIFY "Atmosphere" or Discharging to: (name of abatement device)
Valve Type	Number	Pressure Setting (psig)	Vacuum Setting (psig)	
Combination Vent Valve			-0.03	VRU; atmosphere during VRU downtime
Pressure Vent Valve		0.03		
Vacuum Vent Valve				
Open Vent Valve				

Table 7(a) VERTICAL FIXED ROOF TANK SUMMARY
Page 2
Permit No. ____________________ Tank No. EPN 18

III. ***Liquid Properties of Stored Material***

1. Chemical Category: Organic Liquids [X] Petroleum Distillates [ ] Crude Oils [ ]
2. Single or Multi-Component Liquid

   Single [ ] *Complete Section III.3*

   Multiple [X] *Complete Section III.4*
3. Single Component Information
   a. Chemical Name: ____________________
   b. CAS Number: ____________________
   c. Average Liquid Surface Temperature: __________ °F.
   d. True Vapor Pressure at Average Liquid Surface Temperature: ________ psia.
   e. Liquid Molecular Weight: ____________
4. Multiple Component Information
   a. Mixture Name: Condensate
   b. Average Liquid Surface Temperature: 73.27 °F.
   c. Minimum Liquid Surface Temperature: 53.57 °F.
   d. Maximum Liquid Surface Temperature: 97.38 °F.
   e. True Vapor Pressure at Average Liquid Surface Temperature: 2.876 psia.
   f. True Vapor Pressure at Minimum Liquid Surface Temperature: 1.639 psia.
   g. True Vapor Pressure at Maximum Liquid Surface Temperature: 4.716 psia.
   h. Liquid Molecular Weight: 100.97
   i. Vapor Molecular Weight: 2.8516

j. Chemical Components Information Please see EPA TANKS 4.09d output file

Chemical Name	CAS Number	Percent of Total Liquid Weight (typical)	Percent of Total Vapor Weight (typical)	Molecular Weight

TABLE 8

FLARE SYSTEMS

Number from Flow Diagram EPN 6	Manufacturer & Model No. (if available)

CHARACTERISTICS OF INPUT

Waste Gas Stream	Material	Min. Value Expected	Ave. Value Expected	Design Max.
		(scfm [68°F,14.7 psia])	(scfm [68°F, 14.7 psia])	(scfm [68°F, 14.7 psia])
	1.	See attached emission calculations for details		
	2.			
	3.			
	4.			
	5.			
	6.			
	7.			
	8.			
% of time this condition occurs				

	Flow Rate (scfm [68°F, 14.7 psia])		Temp. °F	Pressure (psig)
	Minimum Expected	Design Maximum		
Waste Gas Stream	See attached emission calculations for details			
Fuel Added to Gas Steam				

	Number of Pilots	Type Fuel	Fuel Flow Rate (scfm [70°F & 14.7 psia]) per pilot
	3	Natural Gas	0.833 scfm/pilot

For Stream Injection	Stream Pressure (psig)		Total Stream Flow	Temp. °F	Velocity (ft/sec)
	Min. Expected	Design Max.	Rate (lb/hr)		

	Number of Jet Streams	Diameter of Steam Jets (inches)	Design basis for steam injected (lb steam/lb hydrocarbon)

For Water Injection	Water Pressure (psig) Min.Expected Design Max.	Total Water Flow Rate (gpm) Min. Expected Design Max.	No. of Water Jets	Diameter of Water Jets (inches)

Flare Height (ft) 75 ft	Flare tip inside diameter (ft) 1.67 ft
Capital Installed Cost $____________	Annual Operating Cost $______________

Supply an assembly drawing, dimensioned and to scale, to show clearly the operation of the flare system. Show interior dimensions and features of the equipment necessary to calculate its performance. Also describe the type of ignition system and its method of operation. Provide an explanation of the control system for steam flow rate and other operating variables.

TABLE 2

MATERIAL BALANCE

This material balance table is used to quantify possible emissions of air contaminants and special emphasis should be placed on potential air contaminants, for example: If feed contains sulfur, show distribution to all products. Please relate each material (or group of materials) listed to its respective location in the process flow diagram by assigning point numbers (taken from the flow diagram) to each material.

LIST EVERY MATERIAL INVOLVED IN EACH OF THE FOLLOWING GROUPS	Point No. from Flow Diagram	Process Rate (lbs/hr or SCFM) standard conditions: 70° F 14.7 PSIA. Check appropriate column at right for each process.	Measurement	Estimation	Calculation
1. Raw Materials - Input					
Inlet Gas	None	200 MMscf/day		X	
Refrigerant Propane	20	30,000 gal/yr		X	
2. Fuels - Input					
Natural Gas		Fuel is from plant residue gas.			
3. Products & By-Products - Output					
Residue Gas	none	160 MMscf/day		X	
High Pressure Condensate	none	345000 bbl/yr		X	
Low Pressure Condensate	17, 18	416,000 gal/yr		X	
NGLs	none	8,256,000 bbl/yr		X	
4. Solid Wastes - Output					
5. Liquid Wastes - Output					
Produced Water	16	416,000 gal/yr		X	
6. Airborne Waste (Solid) - Output	See Table 1(a)	See Emissions Data section			X
7. Airborne Wastes (Gaseous) - Output	See Table 1(a)	See Emissions Data section			X

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APPENDIX G

GHG PSD Permit Application